The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 08-35 February 2, 2009

Petition of New England Gas Company, pursuant to G. L. c. 164, § 94, and 220 C.M.R. §§ 5.00 et seq., for a General Increase in Gas Rates.

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I. INTRODUCTION

A. Procedural History

On July 17, 2008, New England Gas Company ("NEGC" or "Company") filed a petition with the Department of Public Utilities ("Department"), pursuant to G.L. c. 164, § 94, and 220 C.M.R. §§ 5.00 et seq., for a general increase in its base distribution rates for gas customers. The Department docketed the petition as D.P.U. 08-35 and suspended the effective date of the tariffs until February 3, 2009, for further investigation.[1] NEGC's last increase in distribution rates was the result of a settlement agreement between the Company and the Attorney General of the Commonwealth of Massachusetts ("Attorney General"), which was approved by the Department on July 31, 2007. New England Gas Company, D.P.U. 07-46 (2007); see also New England Gas Company, D.P.U. 07-103 (2008).

NEGC is a division of Southern Union Company ("SUG")[2] and provides natural gas distribution service to approximately 53,000 residential and commercial and industrial ("C&I") customers in six Massachusetts communities: (1) 48,200 customers in Fall River, Somerset, Swansea, and Westport ("Fall River service area"); and (2) 4,800 customers in North Attleborough and Plainville ("North Attleboro service area") (Exhs. NEGC-DLB at 2; NEGC-JDS-1, at 7). The two service areas represent the service territories of the former

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1 NEGC filed for approval of tariffs M.D.P.U. No. 1000 through M.D.P.U. No. 1024.

2 SUG's main focus is on gas gathering and transmission services through its companies and subsidiaries such as (1) Sid Richardson Energy Services Ltd, (2) Panhandle Eastern Pipeline Company, LP, (3) Southwest Gas Storage Company and Trunkline LNG Company, LLC, and (4) CrossCountry Energy, LLC (Exh. NEGC-DLB at 3-4).

Fall River Gas Company ("FRG") and the former North Attleboro Gas Company ("NAG"), respectively. Both companies merged with SUG in September 2000. In addition to the approximately 53,000 customers it currently serves in Massachusetts, SUG provides natural gas local distribution service to approximately 500,000 customers in Missouri through Missouri Gas Energy ("Missouri Gas") (Exh. NEGC-DLB at 3).

On July 23, 2008, the Attorney General filed a notice of intervention pursuant to G.L. c. 12, § 11E. On September 3, 2008, the Department granted intervenor status to the Massachusetts Department of Energy Resources ("DOER"), and Local 431, Utility Workers Union of America, AFL-CIO ("Local 431"). Also on September 3, 2008, the Department granted limited participant status to Boston Gas Company, Colonial Gas Company, Essex Gas Company, Massachusetts Electric Company, and Nantucket Electric Company, each doing business as National Grid; Fitchburg Gas and Electric Light Company; and The Berkshire Gas Company.

Pursuant to notice duly issued, the Department held two public hearings: (1) in Fall River on September 8, 2008; and (2) in North Attleboro on September 9, 2008. The Department held ten days of evidentiary hearings between October 6, 2008, and October 24, 2008.

The Attorney General and Local 431 submitted initial briefs on November 12, 2008. NEGC submitted its initial brief on November 24, 2008. The Attorney General and Local 431 submitted reply briefs on December 4, 2008. The Company submitted its reply brief on

December 10, 2008. The evidentiary record consists of 665 exhibits and responses to 129 record requests.

In support of its filing, NEGC sponsored the testimony of eight witnesses: (1) David L. Black, chief operating officer of NEGC; (2) James J. Carey, marketing manager for NEGC; (3) Janet M. Simpson, partner of Dively and Associates; (4) Frank J. Hanley, principal and director of AUS Consultants; (5) Paul M. Normand, principal with Management Applications Consulting, Inc.; (6) James D. Simpson, vice president with Concentric Energy Advisors ("Concentric"); (7) David A. Heintz, assistant vice president at Concentric; and (8) Michael J. McLaughlin, senior vice president and treasurer of SUG.

B. Procedural Rulings

1. Motion to Dismiss

a. Introduction

On September 26, 2008, the Attorney General submitted a motion asking that the Department dismiss either NEGC's request for a general increase in rates in this docket or the Company's earnings sharing mechanism ("ESM") petition submitted on September 17, 2008, and docketed as D.P.U. 08-64.[3] On October 3, 2008, NEGC submitted an opposition to the Attorney General's Motion.

[3] Many of the assertions set forth by the Attorney General are also contained in her comments and reply comments submitted in D.P.U. 08-64.

b. Positions of the Parties

i. Attorney General

In seeking dismissal of the current matter, the Attorney General contends that in submitting two separate requests for increases in distribution rates under alternative methods, the Company is inappropriately seeking to double-collect costs in violation of the settlement approved in D.P.U. 07-46 (Attorney General Motion to Dismiss at 2, citing D.P.U. 07-46 Settlement at Article 2, § 2.1). The Attorney General argues that because both the ESM filing and the instant matter are based on an overlapping test year, Department precedent requires that one of the two petitions be rejected (id. at 5, citing Boston Edison Company, D.P.U. 1720, Interlocutory Order at 7-11 (1984); Massachusetts Electric Company, D.P.U. 19257, at 5-7 (1977)). In the Attorney General's initial and reply briefs, she reiterates her request that the Department dismiss this matter.

In further support of her motion, the Attorney General asserts that NEGC's books and records cannot be relied upon, thus requiring dismissal (Attorney General Brief at 9; Attorney General Reply Brief at 4). The Attorney General contends that the Company's annual returns are the primary source used to support the requested rate increase (Attorney General Brief at 9, citing Whitinsville Water Company, D.P.U. 96-111, at 8 (1997). The Attorney General asserts that Company has failed to file its annual returns in compliance with G.L. c. 164, § 83, and 220 C.M.R. § 79.01. Specifically, she claims that the format of the annual returns submitted by NEGC does not comport with that required by the Department and the appropriate signatories (president, vice-president, treasurer, or assistant treasurer) did not attest to the validity of the annual returns as required by G.L. c. 164, § 83 (id. at 11-12, citing Exh. AG 1-2, Atts. A(1), A(2), B(1), B(2), C(1), C(2)). The Attorney General also argues that the Company failed to appropriately file its annual returns with the municipalities in which it operates, further demonstrating a pattern of non-compliance with Massachusetts statutes and Department regulations (id. at 15-16, citing G.L. c. 164, § 84A).

The Attorney General also argues that the information contained in the Company's annual returns are deficient and unreliable. Specifically, the Attorney General contends that NEGC's chief operating officer would not or could not attest to the accuracy of the financial data contained in the Company's annual returns (id. at 13-14). The Attorney General further asserts that the Company made numerous changes to its cost of service during the proceeding, which demonstrates the unreliability of the annual returns (id. at 14-15, citing, e.g., Exh. NEGC-JMS-2, at 8, 11-14, 16-22, 25-28; Tr. 7, at 890-895; Attorney General Reply Brief at 7-9). Finally, the Attorney General urges the Department to open an investigation to determine the extent to which the Company has failed to comply with Department requirements and also to assess appropriate penalties pursuant to G.L. c. 164, § 84 (Attorney General Reply Brief at 10).

ii. Company

NEGC contends that the Attorney General has procedurally failed to meet the Department's standard of review for motions to dismiss (Company Opposition to Motion to Dismiss at 4). NEGC argues that a motion to dismiss requires the Department to determine whether a petitioner has failed to state a claim upon which relief can be granted and, in this case, the Attorney General has not demonstrated, or even alleged, that the Company cannot prove facts in support of its proposed rate increase (id. at 4-5).

The Company also argues that the Attorney General's interpretation of the D.P.U. 07-46 settlement is patently flawed and that there is no support for her position that NEGC's decision to file both a base rate case and an ESM rate adjustment violates such settlement (id. at 6-7). In addition, NEGC asserts that Department precedent does not prohibit the Company from filing a base rate case and an ESM rate adjustment at the same time (id. at 11, citing Bay State Gas Company, D.P.U. 07-74 (2007)).

As to the reliability of the Company's books and records, NEGC asserts that the Attorney General has not identified any material errors or substantive changes to the Company's actual cost of service calculations (Company Brief at 10). The Company argues that the Attorney General, by attacking the Company's annual returns, has employed a strategy that is designed to cast doubt on the veracity of the Company's books through mischaracterizations of record evidence (id.). NEGC contends that annual returns are regulatory reports and do not constitute the Company's "records and books of accounts" (id. at 11). That is, NEGC asserts that the information is reported in its annual returns pursuant to Department requirements but that the annual returns do not constitute an accounting system that replaces NEGC's financial accounting practices and procedures (id. at 12, 14, citing Exh. NEGC-JMS at 7-9). NEGC also contends, contrary to the Attorney General's assertions, that the annual return was not the basis of its revenue requirement calculation and that, instead, the Company used detailed transactional data obtained directly from its financial systems (id. at 16, citing Exh. NEGC-JMS at 7-9; Tr. 5, at 532, 577).

The Company also maintains that adjustments made by it during the course of this proceeding were to comply with the Department's ratemaking precedent and not to correct alleged errors in the annual returns (id. at 17, citing Tr. 1, at 27; Tr. 5, at 536-540). The Company asserts that the adjustments made during the proceeding are neither unusual nor do they reflect inherent deficiencies in its books or annual returns (id. at 18).

In addition, the Company asserts that it does not have a president, vice-president, treasurer, or assistant treasurer in its corporate structure and, thus, NEGC's chief operating officer and manager of finance signed the annual returns (id. at 13). The Company also argues that the chief operating officer attested to the accuracy of the annual returns by his signature and during the instant proceeding (id. citing Tr. 1, at 22-23). NEGC also contends that the only alleged "error" the Attorney General could point to in the Company's 2007 annual return involves the classification of $162,992 of plant as completed construction not classified ("CCNC") (id. at 15). The Company contends that it explained during the proceeding that the annual return correctly did not include this amount (id. at 15, 27). NEGC asserts that the $162,992 in plant was reported in the construction work in progress ("CWIP") account on the Company's books and the costs had not been transferred to the plant in service account prior to filing its 2007 annual return (id.).

With respect to the numerous errors alleged by the Attorney General in her reply brief, the Company asserts that the dollar amount differences between NEGC's books and the annual return represent differences between the way the Company reflects various items in its service area accounts and the way those items should be treated when developing a complete and fully normalized cost of service in a general rate case (Company Reply Brief at 6-7). The Company also asserts that the majority of those alleged errors were highlighted by NEGC itself in its initial filing (id. at 7).

c. Analysis and Findings

The Department's Procedural Rule, 220 C.M.R. § 1.06(6)(e), authorizes a party to move for dismissal of "all issues or any issue in [a] case" at any time after the filing of an initial pleading. The Department's current standard for ruling on a motion to dismiss for failure to state a claim upon which relief can be granted was articulated in Riverside Steam & Electric Company, D.P.U. 88-123, at 26-27 (1988). In D.P.U. 88-123, at 26-27, the Department denied the respondent's motion to dismiss, finding that it did not appear "beyond doubt that [the petitioner] could prove no set of facts in support of its petition."[4]

In determining whether to grant a motion to dismiss, the Department takes the assertions of fact as true and construes them in favor of the non-moving party. D.P.U. 88-123, at 26-27. Dismissal will be granted by the Department if it appears that the

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4 Although D.P.U. 88-123 refers to Massachusetts Rule of Civil Procedure 12(b)(6), the Department has not adopted Rule 12(b)(6). See Attorney General v. Department of Public Utilities, 390 Mass. 208, 212-213 (1983) (rules of court do not govern procedure in executive Department). Rules of court, while not binding on the Department, may provide instructive guidance. Massachusetts Institute of Technology, D.P.U. 94-101/95-36, at 11 n.5 (1995).

non-moving party would be entitled to no relief under any statement of facts that could be proven in support of its claim. Id.

In order for the Attorney General to prevail in a motion to dismiss, she would need to prove that there are no circumstances under which the Company would be entitled to a review of its proposed request for a general increase in base distribution rates. For the reasons stated below, the Departments finds that the Attorney General has not met this burden.

The Attorney General argues that NEGC is seeking to double-collect by requesting both a base rate distribution increase and an ESM rate adjustment and that both filings are based on an overlapping test year. The Department will consider, in this Order, only the appropriateness of dismissing the instant proceeding. The Department addresses the appropriateness of the dismissing the ESM rate adjustment petition in New England Gas Company, D.P.U. 08-64-B (Feb. 3, 2009).

In asserting that the Company's books and records are unreliable, the Attorney General alleges that NEGC has demonstrated a pattern of non-compliance with Massachusetts laws and Department regulations (Attorney General Brief at 11, 15-16; Attorney General Reply Brief at 6).[5] Specifically, the Attorney General contends that "the lack of a signed annual return is a fatal flaw" and that its failure to file the appropriate condensed with municipalities further

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5 The Attorney General also contends that, in each instance, NEGC filed only a condensed annual return rather than the full annual return required by G.L. c. 164, § 83. The Department has reviewed the annual returns and determined that while the cover page is labelled "condensed," the documentation contains both the condensed annual return and a full annual return.

demonstrates the Company is failing its fiduciary duty (Attorney General Brief at 15-16; Attorney General Reply Brief at 5).

Pursuant to G.L. c. 164, § 83, annual returns must be "signed and sworn to by the president or vice president, and treasurer or assistant treasurer, and a majority of the directors." Pursuant to G.L. c. 164, § 84A, condensed annual returns must be submitted to each municipality in a gas company's service territory. For 2005 through 2007, NEGC's annual returns were not signed by the Company's president or vice president, and treasurer or assistant treasurer, and a majority of the directors nor were the condensed annual returns submitted to each municipality in its service territory (see Exh. AG 1-2, Atts. A(1), A(2), B(1), B(2), C(1), C(2); RR-AG-1). The purpose of obtaining such signatures is to ensure that a senior company official is attesting to the veracity of the data. In this case, NEGC claims that it does not have the named positions in its corporate structure.[6] As an alternative, the annual returns were signed by NEGC's chief operating officer and its manager of finance (see, e.g., Exh. AG 1-2, Att. (A)(2) at 1, 4, 81). Further, and contrary to the Attorney General's assertions, the Company's chief operating officer attested to the validity of the annual returns on behalf of NEGC (see Tr. 1, at 19, 21, 26). Thus, we do not find that the lack of the named signatories rises to the level of rendering the annual returns materially defective as to merit dismissal of the rate case.

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6 In view of NEGC's status as a division of SUG, which has a president and other corporate officers, we interpret NEGC's statement as referring to the Company's local management presence.

Nonetheless, we expect companies to meet reasonable accounting standards so that the Department may fulfill its statutory obligation to the ratepayers of the Commonwealth by properly reviewing those companies under our jurisdiction. Accordingly, we direct NEGC in the future to submit annual returns that have been appropriately signed as required by G.L. c. 164, § 83, with the understanding that this will require NEGC to obtain signatures from senior officials at SUG. In addition, NEGC must provide the municipalities in its service areas with the appropriate condensed annual returns as required by G.L. c. 164, § 84A.

The Attorney General also argues that the annual returns contain numerous errors (Attorney General Brief at 11). The Attorney General, however, does not identify any specific accounting errors for NEGC to address and the Department to review (see, e.g., Tr. 1, at 24-26). Instead, the Attorney General cites to adjustments made by the Company in its initial filing and during the course of the proceeding.

Accounting requirements do not necessarily dictate ratemaking treatment. The accounting systems prescribed by the Department, including the USOA-Gas Companies codified as 220 C.M.R. §§ 50.00 et seq., represent systems whereby costs are categorized to provide the Department with information on utility operations and aid in the review of utility costs; they do not establish either the reasonableness per se of the reported costs or the ratemaking treatment to be accorded such costs. See, e.g., Boston Gas Company, D.T.E. 03-40, at 103, 208 (2003); Boston Edison Company, D.P.U./D.T.E. 97-95, at 77 (2001). In addition, there are numerous adjustments made to expenses and plant in preparing a rate case, all of which are appropriate to consider.[7] Such adjustments are a routine part of rate case proceedings and do not imply that any deficiency exists in the particular company's annual return.

In addition, we note that the Attorney General has requested and the Department has opened a proceeding to conduct an independent audit of the Company's records pursuant to G.L. c. 25, § 5E. See New England Gas Company, D.P.U. 08-110. If, as a result of that proceeding, it is determined that NEGC's books are deficient or unreliable, the Department on its own motion or at the request of the Attorney General may commence a proceeding pursuant to G.L. c. 164, § 93. Because the Attorney General has failed to prove that there are no circumstances under which NEGC would be entitled to a general rate increase, the Attorney General's Motion to Dismiss is denied.

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7 For example, it may be necessary to normalize test year expense by reversing accounting entries made during the test year. See, e.g., D.P.U. 02-24/25, at 73. Non-recurring expenses may also be removed from cost of service. See, e.g., Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 33 (1983). Expenses may even be removed from cost of service, such as lobbying costs or fines that had been booked above the line. See, e.g., Boston Gas Company, D.P.U. 88-67 (Phase I) at 142-143 (1988). It is also common to reallocate test year expenses associated with non-utility operations (like appliance rental affiliates) based on updated allocation factors. See, e.g., The Berkshire Gas Company, D.P.U. 90-121, at 68 (1990). In addition, it may also be appropriate to make various billing adjustments, such as those intended to reconcile unbilled revenues. See, e.g., D.P.U. 03-40, at 10; Oxford Water Company, D.P.U. 86-172, at 6-7 (1987).

2. Motion to Strike Portions of the Company's Initial Brief

a. Introduction

On December 4, 2008, the Attorney General filed a motion to strike portions of NEGC's initial brief, pursuant to 220 C.M.R. §§ 1.04(5) and 1.11(7), (8) ("Motion to Strike"). NEGC filed an opposition to the motion on December 11, 2008 ("Opposition to Motion to Strike"). The Attorney General specifically seeks to strike (1) information derived from the Company's annual returns from 1999 through 2004, and (2) references to bond-related information obtained from various sources published after the conclusion of testimony by the Company's cost of capital and rate of return witness (Motion to Strike at 1).

With respect to the annual returns, the Company asked in its brief that the Department incorporate the information by reference pursuant to 220 C.M.R. § 1.10(3) (Company Brief at 5 n.6).[8] The Company did not make any request to enter the bond-related information into the record and simply cited the information in its brief (id. at 111).

b. Positions of the Parties

i. Attorney General

The Attorney General asserts that the portions of the brief she seeks to strike consist of extra-record evidence because the information was neither (1) produced during the hearings, nor (2) preceded by a motion to reopen the record to admit such post-hearing evidence (Motion to Strike at 2-3). The Attorney General asserts that inclusion of the information would violate

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[8] NEGC's annual returns from 2005 through 2007 were previously entered into the evidentiary record (see Exh. AG 1-2, Atts. A, B, and C; see also Tr. 10, at 1390).

the Department's procedural rules and would violate the Attorney General's and other intervenors' procedural rights pursuant to G.L. c. 30A, § 11(3) (id. at 3, citing MediaOne/New England Telephone, D.T.E. 99-42/43, at 17-18 (1999); Boston Edison Company, D.P.U. 90-335, at 7-8 (1992); Payphone Inc., D.P.U. 90-171, at 4-5 (1991); G.L. c. 30A, § 11; 220 C.M.R. §§ 1.11(4), 1.11(7), and 1.11(8)). The Attorney General asks that the Department either (1) strike the information at issue from the Company's brief and require NEGC to file a conforming brief or (2) strike the portions of the brief and disregard them in reaching a decision in the case (id. citing, e.g., Boston Edison Company v. Brookline Realty & Inv. Corp., 10 Mass. App. Ct. 63, 69 (1980); AT&T Communications, D.P.U. 91-79, at 8 (1992); D.P.U. 90-335, at 7-9).

ii. Company

NEGC asserts that it is appropriate to permit inclusion of information from its annual returns and bond-related information. Specifically, the Company argues that the information related to the Company's annual returns can be incorporated by reference pursuant to 220 C.M.R. § 1.10(3) while the information related to the yield of utility bonds and utility bond ratings can be recognized through official, or administrative, notice pursuant to 220 C.M.R. § 1.10(2) (Opposition to Motion to Strike at 1). NEGC contends that the Department routinely takes administrative notice of a utility's annual returns (id. citing Eastern Enterprises/Colonial Gas Company, D.T.E. 98-128, at 84 n.64 (1999), NIPSCO/Bay State Gas Company, D.T.E. 98-31, at 48 n.45 (1998)). NEGC further contends that the annual returns are exactly the type of information that the Department should consider under 220 C.M.R. § 1.10(3) (id. at 2).

As to the bond-related information, the Company asserts that the information is relevant to describe current financial conditions (id. at 3). NEGC further contends that the information is publicly available and is not the work product of an expert who would be subject to cross examination (id.).

c. Analysis and Findings

For the following reasons, the Department grants the Attorney General's Motion to Strike. It is axiomatic that a party's post-hearing brief may not serve the purpose of presenting facts or other evidence that is not in the record. As the Department stated in Boston Gas Company, D.P.U. 88-67, at 7 (Phase II) (1989), a party's presentation of extra-record evidence to the fact-finder after the record has closed is an unacceptable tactic that is potentially prejudicial to the rights of other parties even when the evidence is excluded. We are further guided by our regulations which state that no person may present additional evidence after having rested except upon motion and a showing of good cause. 220 C.M.R. § 1.11(8). The Department's "good cause" standard provides that good cause is a relative term and it depends on the circumstances of an individual case. Good cause is determined in the context of any underlying statutory or regulatory requirement and is based on a balancing of the public interest, the interest of the party seeking an exception, and the interests of any other affected party. Nunnally d/b/a L & R Enterprises, D.P.U. 92-34-A at 3 (1993), citing Boston Edison Company, D.P.U. 90-335-A at 4 (1992). Good cause for purposes of reopening a record has been defined as a showing that the proponent has previously unknown or undisclosed information regarding a material issue that would be likely to have a significant impact on the decision. Commonwealth Electric Company, D.T.E. 04-78, at 4-5 (2005); D.P.U. 88-67 (Phase II) at 7; Tennessee Gas Pipeline Company, D.P.U. 85-207-A at 11-12 (1986).

First, we find that the Company's effort to have the Department incorporate by reference the Company's annual returns from 1999 to 2004 is procedurally defective. That is, the Company did not submit the required motion to reopen the record pursuant to 220 C.M.R. § 1.11(8). Further, even if we were to consider the Company's request in its brief as attempt to include the annual return information on brief as a "motion to reopen the record," NEGC has failed to show good cause to reopen the record at this late stage in the proceeding.

The Department's procedural rules at 220 C.M.R. § 1.10(2) permit a party to request that the Department incorporate information by reference or take administrative notice of documents. Specifically, a party may ask the Department to incorporate by reference any documents in the Department's possession or take administrative notice of matters that a party wishes to use as evidence. 220 C.M.R. § 1.10(2). NEGC is correct that a company's annual return is the type of document that the Department routinely takes administrative notice of. See, e.g., D.P.U. 98-128, at 56 n.36; Boston Edison Company, D.T.E. 99-19, at 26 n.21 (1999). Had the Company asked the Department to incorporate the annual returns into the record by reference prior to the close of the evidentiary record, it is likely that the Department would have allowed the request because the Attorney General and the other intervenors would not have been prejudiced (i.e., there would have been the opportunity to cross examine or submit rebuttal evidence).[9]

Nonetheless, because the Company's request to incorporate the documents by reference occurred after the close of the evidentiary record, the request should have been accompanied by a motion to reopen the record pursuant to 220 C.M.R. § 1.11(8). Even if the Company had moved to reopen the record, we find there was ample opportunity during the discovery and evidentiary hearing phase of this proceeding for NEGC to request that the Department incorporate the Company's annual returns for 1999 through 2004 into the record. As noted above, the Company's annual returns for 2005 through 2008 were appropriately entered into the evidentiary record (see Exh. AG 1-2, Atts. A, B, and C; Tr. 10, at 1390). Because the Company has failed to demonstrate good cause for its failure to request that the Department incorporate by reference the annual returns for 1999 through 2004 prior to the close of the record, the Department will strike the portions of NEGC's brief referencing facts and arguments related to its annual returns for the years 1999 through 2004 and will not rely on them in reaching our decision in the case.[10]

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9 In its brief, the Company also requested that the Department incorporate by reference NEGC's annual service quality report filed on March 1, 2008, in D.P.U. 08-22 (Company Brief at 121 n.25). Although this request was also made after the close of the evidentiary record and, therefore, suffers from the same procedural defect, no party objected to this request. Therefore, we find there is no prejudice to any party and the annual service quality report is incorporated into the evidentiary record in this case.

10 Pursuant to the Attorney General's request, we are striking from NEGC's initial brief

(continued...)

As to the bond-related information, the Company made no procedural request to enter the information into the record; instead, the Company simply cited the information as evidence (Company Brief at 111). Absent a motion to reopen the record to admit evidence, we find that the Company's effort to introduce the bond-related information into the record is procedurally defective. While the information may not have been available prior to the record being closed, NEGC made no showing that such information regarded a material issue that would have a significant impact on the outcome of the case. As stated earlier, for the Department to take the unusual step of reopening a record, good cause must be shown. Because the Company did not show good cause why the record should be reopened to admit the bond-related information, the Department will strike from NEGC's brief reference to bond yields as of November 2008, and Pacific Gas & Electric Company's bond issuance of October 15, 2008, and will not rely on them in reaching our decision in the case.[11]

II. RATE BASE

A. Plant Additions

1. Introduction

Between January 1, 2006, and December 31, 2007, NEGC placed into service $8,060,405 of new plant, mostly related to distribution mains and services (Exh. AG 1-2,

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10 (…continued) the last three sentences of page 4, page 5 in its entirety, and the first three sentences of page 6.

11 Pursuant to the Attorney General's request, we are striking from NEGC's initial brief the last paragraph of page 124 and page 125 in its entirety.

Atts. A(1) at 18, A(2) at 18, B(1) at 18, B(2) at 18). Plant additions can be classified in two ways: (1) revenue-producing (i.e., discretionary) plant such as new mains associated with new customers or increased load; and (2) non-revenue producing (i.e., non-discretionary) plant associated with activities needed to maintain system safety and reliability or key processes, such as main replacements, peak-shaving plant, and information technology upgrades (Tr. 7, 846-847; RR-DPU-37). In the case of discretionary projects, NEGC uses an internal rate of return ("IRR") analysis to determine whether the revenue stream expected from the additional load associated with the proposed project is at least equal to the Company's weighted average cost of capital ("WACC") (Tr. 7, at 849-850; RR-DPU-37). While the Company's IRR model is based on an initial hurdle rate of 9.15 percent, the Company states that it uses a higher threshold rate in order to ensure that its investment in discretionary projects produce significant returns (Tr. 7, at 849-850).

NEGC identified all capital projects completed between January 1, 2006, and December 31, 2007, that were greater than $50,000 and provided work orders and closing reports for capital projects in excess of $50,000 for the years 2003 through 2005 (Exhs. NEGC-JMS-5; DPU 4-11).[12] The information included the year the project was undertaken, the name of the project, the location of the project, a description of the project, and identified how much the actual cost deviated from the initial cost estimate (Exhs. NEGC-JMS-5; DPU 4-11).

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12 The Company's capital authorization policy requires an economic analysis of projects in excess of $50,000 (see Exh. DPU 4-11, Atts. A, B).

2. Positions of the Parties

NEGC contends that it has examined all projects that exceeded $50,000 that were added to plant in service since its last rate case,[13] and has fully documented the original budgets and actual costs, as well as provided budget variances and variance explanations (Company Brief at 23, citing Exhs. NEGC-JMS at 26; NEGC-JMS-5). The Company maintains that there were no major customer growth-related projects during that period and that its distribution plant projects were undertaken for system integrity reasons, including replacing bare steel and cast iron mains, as well as improving pressure on the system (id. at 23-24). No other party addressed plant additions.

3. Analysis and Findings

a. Introduction

For costs to be included in rate base, the expenditures must be prudently incurred and the resulting plant must be used and useful to ratepayers. Western Massachusetts Electric Company, D.P.U. 85-270, at 20 (1986). The prudence test determines whether cost recovery is allowed at all, while the used and useful analysis determines the portion of prudently incurred costs on which the utility is entitled to earn a return. Id. at 25-27.

A prudence review involves a determination of whether the utility's actions, based on all that the utility knew or should have known at that time, were reasonable and prudent in light of the extant circumstances. Such a determination may not properly be made on the basis

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13 By "last rate case," the Company is referring to the settlement agreement in D.P.U. 07-46.

of hindsight judgments, nor is it appropriate for the Department merely to substitute its own judgment for the judgments made by the management of the utility. Attorney General v. Department of Public Utilities, 390 Mass. 208, 229 (1983). A prudence review must be based on how a reasonable company would have responded to the particular circumstances and whether the company's actions were in fact prudent in light of all circumstances that were known or reasonably should have been known at the time a decision was made. Boston Gas Company, D.P.U. 93-60, at 24-25 (1993); D.P.U. 85-270, at 22-23; Boston Edison Company, D.P.U. 906, at 165 (1982). A review of the prudence of a company's actions is not dependent upon whether budget estimates later proved to be accurate but rather upon whether the assumptions made were reasonable, given the facts that were known or that should have been known at the time. Massachusetts-American Water Company, D.P.U. 95-118, at 39-40 (1996); D.P.U. 93-60, at 35; Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A at 26 (1985), citing Boston Gas Company, D.P.U. 555-C at 16 (1983).

The Department has found that a gas utility need not serve new customers in circumstances where the addition of new customers would raise the cost of gas service for existing firm ratepayers. D.T.E. 03-40, at 48; D.P.U. 88-67 (Phase I) at 282-284. The Department stated that existing customers receive benefits whenever, all other things being equal, the return on incremental rate base exceeds the company's allowed overall rate of return. Boston Gas Company, D.P.U. 89-180, at 16-17 (1990).

The Department has cautioned utility companies that, as they bear the burden of demonstrating the propriety of additions to rate base, failure to provide clear and cohesive reviewable evidence on rate base additions increases the risk to the utility that the Department will disallow these expenditures. Massachusetts Electric Company, D.P.U. 95-40, at 7 (1995); D.P.U. 93-60, at 26; The Berkshire Gas Company, D.P.U. 92-210, at 24 (1993); see also Massachusetts Electric Company v. Department of Public Utilities, 376 Mass. 294, at 304 (1978); Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, at 24 (1967). In addition, the Department has stated that:

> In reviewing the investments in main extensions that were made without a cost-benefit analysis, the Company has the burden of demonstrating the prudence of each investment proposed for inclusion in rate base. The Department cannot rely on the unsupported testimony that each project was beneficial at the time the decision was made. The Company must provide reviewable documentation for investments it seeks to include in rate base.

D.P.U. 92-210, at 24.

b. Discretionary Projects

Between 2003 and 2007, the Company completed two discretionary projects with a total cost in excess of $50,000.[14] The first project, the Harris Farm residential housing development ("Harris Farm") is a 41-home subdivision in North Attleboro with a potential development of 50 homes (Exh. DPU 4-11, Att. A; RR-DPU-37). The other project is the Davol Street/Riverside ("Davol/Riverside") project, consisting of the replacement of an aging 8-inch main with a 12-inch main extended to serve the Montaup Electric Company's generating

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14 The Department has found that analyzing projects in excess of $50,000 strikes a reasonable balance between the need for effective regulatory review of the Company's capital projects and the need to avoid devoting considerable resources to the examination of variances in relatively low-cost projects. See Bay State Gas Company, D.T.E. 05-27, at 76 (2005).

station in Somerset (Exh. DPU 4-11, Atts. A, B; RR-DPU-37). Both projects were completed during 2005 at a total cost that was less than originally estimated (Exh. DPU 4-11, Atts. A, B; RR-DPU-37). Based on the results of the IRR analyses performed for these projects, NEGC determined that customer contributions in aid of construction ("CIAC") would be appropriate in order to make the investments cost-effective (RR-DPU-37).[15]

The Harris Farm and Davol/Riverside projects were placed into service prior to the end of the 2007 test year in this proceeding and are currently providing net economic benefits to customers. Therefore, the Department finds that these projects are used and useful. Boston Gas Company, D.P.U. 96-50 (Phase I) at 23-24 (1996); D.P.U. 85-270, at 60-63. Concerning the costs of the Harris Farm and Davol/Riverside projects, the Department has reviewed the supporting project documentation, including the work authorizations and contractor construction reports (Exh. DPU 4-11, Att. B; RR-DPU-37).[16] Based on this review, we find that NEGC acted prudently in estimating the throughput and costs associated with these projects. Additionally, the Company received CIAC of $335,098 for the Harris Farm project and $1,076,456 for the Davol/Riverside project (Exh. DPU 4-11, Att. A; RR-DPU-37). Based

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15 The customer contribution represents the amount of funds required from the customer to ensure that the revenue stream expected from the load addition will exceed the cost incurred by NEGC to add the load by a margin that is greater than the Company's WACC as approved by the Department in the Company's last base-rate proceeding (RR-DPU-37).

16 Well-organized and fully-documented information on capital additions facilitates both Department and intervenor review. See Bay State Gas Company, D.P.U. 05-27, at 94 n.68 (2005). In the future, the Department expects companies to present their capital additions in an organized manner that fully identifies capital projects, their associated costs, variances from budgeted estimates, and the reasons for any variances.

on this information, the Department finds that the Company's decision to embark on the Harris Farm and Davol/Riverside projects was prudent. Accordingly, we will allow the cost of these projects to be included in rate base.

c. Non-Discretionary Projects

For the period 2003 through 2007, NEGC identified 35 non-discretionary projects with a total cost of more than $50,000 that were completed and placed into service during that time (Exhs. NEGC-JMS-5; DPU 4-11, Att. A; RR-DPU-37). Of these projects, twelve experienced cost overruns, with six projects experiencing cost overrruns in excess of 20 percent (i.e., between 36.4 percent and 77.9 percent (Exh. DPU 4-11, Att. A). Cost overruns can be incurred on a project for a wide range of reasons that can be outside of a company's control and the existence of such overruns in and of themselves do not necessarily demonstrate imprudence on a company's part in the planning or construction of the project. Bay State Gas Company, D.T.E. 05-27, at 80-82 (2005).

For those six projects with cost overruns of less than 20 percent, the Department has reviewed the supporting documentation, including the capital authorizations, work order ledgers, construction and maintenance work orders, and daily contractor construction reports (Exh. DPU 4-11, Att. B). The Department finds that the Company has provided sufficient and reviewable evidence to demonstrate that it has controlled costs and that the project expenditures were prudent.[17] Additionally, the Department finds that the Company has engaged in

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17 To illustrate the issues that may arise during construction, the County Street project involved the replacement of bare steel mains with plastic mains and had a project (continued...)

appropriate cost-containment measures (Exh. NEGC-JMS-5). The Department's review of the supporting documentation leads us to conclude that NEGC acted prudently in estimating the costs associated with these projects, and that the reasons for cost overruns include factors that could not have been reasonably anticipated during the preparation of the construction estimates, such as the need for additional trenching, the presence of ledge, conditions of service lines, and the unexpected need for design modifications as a result of site conditions (Exh. DPU 4-11, Att. B). Accordingly, we will allow the costs of these projects to be included in rate base.

For those six projects with cost overruns of greater than 20 percent, the Department has also reviewed the supporting documentation, including the capital authorizations, work order ledgers, construction and maintenance work orders, and daily contractor construction reports (id., Att. B). Because of the magnitude of the variances associated with these projects, the Department has applied a greater level of scrutiny to the individual projects.

Project 7034-500-CNV, the North Main Street-Freetown Line project, had a total cost of $320,187, or 77.9 percent more than originally estimated (id., Att. A). This project involved the extension of a distribution main to an Algonquin Gas Transmission gate station located in Freetown and also allowed the Company to add customers from a local industrial

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[17] (…continued)
estimate of $119,685 (Exh. NEGC-JMS-5, at 1). The completed cost of the project was $137,842, representing an increase of $18,157, or approximately 15.2 percent (id.). The Company explained that while the original plan was to lay the new mains under the sidewalk, more of the mains had to be laid in the roadway area, resulting in higher street restoration costs (id.; RR-DPU-37).

park (id., Att. B; Tr. 7, at 845-846). Based on our review of the underlying documentation, we conclude that the Company acted prudently in estimating the costs of this project. The additional costs were incurred, at least in part, because of a required bridge crossing, which is subject to various regulatory requirements that were difficult to quantify during the preparation of construction estimates (Exh. DPU 4-11, Att. B). Accordingly, we will allow the cost of this project to be included in rate base.

Similarly, Project 7079-100, the North Underwood Street project, had a total cost of $49,602, or 71.3 percent more than originally estimated (id., Att. A). This particular project involved the replacement of a two-inch main and required additional manual digging and subcontractor labor to penetrate a granite wall (id., Att. B). Based on these considerations and the Department's review of the underlying documentation, we conclude that NEGC acted prudently in estimating the costs of this project and that the additional costs were incurred as a result of site conditions that could not have been reasonably known at the time the construction estimate was prepared. Accordingly, we will allow the cost of this project to be included in rate base.

Turning to the remaining four projects with costs overruns in excess of 20 percent, the Department's review of the supporting documentation leads us to conclude that the Company acted prudently in estimating the costs associated with these projects. The Department also finds that the additional costs associated with these projects were the result of various factors that could not have been reasonably known at the time the construction estimate was prepared, such as the need for additional trenching, the presence of ledge, conditions of service lines, and unexpected findings during construction (id., Att. B). Accordingly, we will allow the costs of these projects to be included in rate base.

B. North Attleboro Plant Held For Future Use

1. Introduction

In North Attleboro Gas Company, D.P.U. 91-78 (1991), the Department approved a settlement agreement whereby NAG would book $545,000 in distribution mains to plant held for future use and would exclude these mains from future rate base unless the annual throughput was at least 102,377 thousand cubic feet, on a weather-normalized basis, by the beginning of 2000 (Exh. NEGC-JMS at 27; see also D.P.U. 91-78, at 2). On December 29, 1999, NAG informed the Department that the throughput requirement had been achieved within the required time period (Exh. NEGC-JMS at 27). Therefore, NEGC reclassified the $545,000 to plant in service and proposes to include the plant in rate base (id.; Exh. NEGC-JMS-2, Sch. C-5). The Company made a corresponding increase to its accumulated depreciation of $251,904 to recognize the depreciation taken on the distribution mains since the date that the plant satisfied the terms of the D.P.U. 91-78 settlement (Exh. NEGC-JMS-2, Sch. C-6; Tr. 6, at 759-761). While the Company restated its proposal in its initial brief (Company Brief at 28), no other party addressed the issue.

2. Analysis and Findings

The settlement agreement in D.P.U. 91-78 specified that the $545,000 in NAG distribution mains would be booked to plant held for future use and would be excluded from future rate base unless a specified threshold throughput was met by the year 2000.

D.P.U. 91-78, at 2. NAG achieved that throughput requirement by letter dated December 29, 1999 (Exh. NEGC-JMS at 27). The plant remains in service and is used and useful in providing service to customers. The Company has also appropriately recognized the depreciation taken on the plant since it went into service (Exh. NEGC-JMS-2, Sch. C.6). Therefore, the Department finds that the terms of the settlement in D.P.U. 91-78 have been met and the plant is appropriately included in rate base. Accordingly, the Department approves NEGC's proposal to include the $545,000 in distribution plant in rate base, as well as to include $251,904 in accumulated depreciation associated with this plant as part of the Company's depreciation reserve.

C. Cash Working Capital Allowance

1. Introduction

In their day-to-day operations, utilities require funds to pay for expenses incurred in the course of business, including operating and maintenance ("O&M") expenses. These funds are either generated internally by a company or through short-term borrowing. Department policy permits a company to be reimbursed for costs associated with the use of its funds for the interest expense incurred on borrowing. D.P.U. 05-27, at 97; D.P.U. 96-50 (Phase I) at 26, citing Western Massachusetts Electric Company, D.P.U. 87-260, at 22-23 (1988). This reimbursement is accomplished by adding a working capital component to the rate base computation.

Cash working capital needs have been determined through either the use of a lead-lag study or a 45-day O&M expense allowance. D.T.E. 03-40, at 92. In the absence of a lead-lag study, the Department has generally relied on the 45-day convention as reasonably representative of O&M working capital requirements. D.T.E. 05-27, at 98; D.P.U. 88-67 (Phase 1) at 35. The Department, however, has expressed concern that the 45-day convention first developed in the early part of the 20th century no longer provides a reliable measure of a utility's working capital requirements. D.T.E. 03-40, at 92; Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 15 (1998). Therefore, the Department requires each gas and electric distribution company to either (1) conduct a lead-lag study where cost-effective, or (2) propose a reasonable alternative to a lead-lag study to develop a different interval.[18] D.T.E. 03-40, at 92; D.T.E. 02-24/25, at 57.

NEGC conducted a lead-lag study to consider the Company's purchased gas working capital requirements as well as its O&M cash working capital requirements (Exh. NEGC-JMS-2, Sch. D). The purpose of the study was to update the net lag days associated with purchased gas working capital and to establish the net lag days to be used for other O&M expense working capital that will be included in base rates (id., Sch. D). The study determined that the net lag associated with purchased gas expense was 26.11 days, and that the net lag associated with other O&M expense was 22.97 days (RR-DPU-56-A, Sch. D)

The net lag factors represent the difference between a 65.47-day revenue lag and expense leads of 39.36 days and 42.5 days for purchased gas and O&M expense, respectively

[18] In this context, "cost-effective" means that the normalized cost of the study (i.e., the cost of the study divided by the normalization period used in the utility's rate case) is less than the reduction in revenue requirements that would occur using the results of the lead-lag study in lieu of the 45-day convention. D.T.E. 02-24/25, at 57 n.34.

(Exh. NEGC-JMS-3, WP D-2).[19] The 65.47-day revenue lag consists of: (1) a 15.17-day meter reading lag; (2) a 3.44-day billing lag; (3) a 46.49-day collection lag; and (4) a 0.37-day bank deposit lag (id., WP D.2).[20] The purchased gas net lag of 26.11 days represents the difference between the 65.47-day revenue lag and the 39.36-day purchased gas expense lead (RR-DPU-56-A, Sch. D). The O&M net lag of 22.97 days represents the difference between the 65.47-day revenue lag and the 42.5-day O&M expense lead (id., Sch. D). These lag factors, multiplied by their respective purchased gas costs and O&M expense, produce a purchased gas working capital allowance of $4,211,011 and an O&M expense working capital allowance of $1,069,235 (id., Sch D). The Company then added $88,654 in working capital allowance associated with uncollectible expense to be recovered through the cost of gas adjustment clause ("CGAC"), as well as $27,328 in working capital allowance associated with uncollectible expense to be recovered through base rates (id., Sch D). The Company determined these amounts based on the results of NEGC's allocated cost of service study ("COSS") by multiplying the proposed uncollectible expense, broken down by CGAC-recoverable and base rate-recoverable amounts, by their respective lead-lag factors (id.,

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19 Revenue lag is the time interval from when a customer begins receiving service for a billing cycle until the customer pays for the service. Expense lead is the time interval from when a good or service is received and when payment is made.

20 The billing lag component represents the period between meter readings and the billing date (Exh. NEGC-JMS-3, WP D.3.6; Tr. 10, at 1292-1293). The bank deposit lag component represents the time between receipt of payment by the Company's billing system and deposit of the funds (Exh. NEGC-JMS-3, WP D.5.1; Tr. 10, at 1294).

Sch D). Therefore, NEGC determined that its total cash working capital allowance was $5,396,227 (id., Sch. D).

This total cash working capital requirement was then allocated between the Company's base rates and CGAC, based on the results of its cost allocation study (Exhs. NEGC-JMS at 30; Tr. 12, at 1329). Consequently, NEGC proposed the following: (1) purchased gas cash working capital allowance of $4,211,011; (2) other O&M expense cash working capital allowance of $1,069,235; (3) CGAC-recoverable cash working capital allowance associated with uncollectible expense of $88,654; and (4) distribution rate-recoverable cash working capital associated with uncollectible expense of $27,328 (id., Sch D).

2. Positions of the Parties

a. Attorney General

The Attorney General claims that the Company's cash working capital allowance proposal is inconsistent with Department precedent (Attorney General Brief at 18). First, the Attorney General posits that the Company initially proposed to include expenses, such as property, income, and payroll taxes, that do not belong in the calculation of cash working capital allowance (id. citing Exh. NEGC-JMS-2, Sch. D). The Attorney General notes that, in a response to a Department record request, the Company removed from its cash working capital calculation property, payroll, and income taxes, as well as uncollectible expense and gas-related costs whose working capital allowances are collected through other rate components (id. citing Exh. NEGC-JMS-2, Sch. D (Rev. 11/3/08); RR-DPU-63; Tr. 10, at 1333-1337). The Attorney General states that the Department should ensure that these expenses are excluded from the cash working capital allowance when determining the Company's rate base by using the Company's response to record request DPU-63 as the basis for calculating cash working capital (id.).

Second, the Attorney General argues that the Company's lead-lag study overstates the necessary billing lag days (id.). In support of her position, the Attorney General states that NEGC admitted that meter-read information is collected electronically and uploaded into the Company's billing system on the same day as it is collected (id. at 20, citing Tr. 7, at 878). Accordingly, the Attorney General maintains that there is no reason that the Company should be allowed any more than one business day for billing lags (id.). The Attorney General takes issue with the Company's assertion that the Attorney General ignores testimony demonstrating NEGC efforts to read customer's meters in an efficient manner (Attorney General Reply Brief at 13-14). The Attorney General argues that holding all bills that are on the same billing cycle until all of the meters on the cycle have been read, as the Company currently does, is an imprudent step that diminishes NEGC's cash flow (id. at 14 n.7). The Attorney General argues that the Department should reject the attempt by the Company to build these inefficiencies, and the resulting higher costs, into the rates the Company charges for services (id.). Taking into consideration the longer billing lag associated with meter readings done on Friday because of the ensuing weekend, the Attorney General concludes that the Company's billing lag should be reduced from 3.44 days to 1.4 days (Attorney General Brief at 21; Attorney General Reply Brief at 14).[21]

Third, the Attorney General argues that the Department should reject the Company's proposed payment lag of 0.37 days that the Company includes in its calculation of the revenue lag (Attorney General Brief at 21). In support of her position, the Attorney General states that the Department has consistently rejected the notion that payment lags should be based on the assumption that payment is made on the date a check clears (id. citing D.T.E. 02-24/25, at 50; Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80 (Phase One) at 22 (1991)). The Attorney General argues that the Company has not provided any new evidence or argument that should cause the Department to change this well-founded precedent (id.).

b. Company

NEGC argues that its cash working capital calculations are consistent with Department precedent and, therefore, no additional adjustments are necessary (Company Brief at 31-34). First, the Company asserts that its revised calculation of cash working capital allowance shows no addition of income taxes and demonstrates that property and payroll taxes have been properly removed (id. at 32, citing Exh. NEGC-JMS-2, and Sch. D). Second, the Company disagrees with the Attorney General that NEGC's billing lag should be reduced to 1.4 days (id. at 32-33). According to NEGC, the Attorney General did not consider that the Company

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21 According to the Attorney General, the record shows that the billing lag for Monday through Thursday is one day, and for Friday, the billing lag is three days, assuming that a bill is produced on the next business day (i.e., Monday) (Attorney General Brief at 21, citing Tr. 7, at 880-881). Using these daily lags, the Attorney General calculates the average billing lag as (1+1+1+1+3) / 5 = 1.4 (id. at 21 n.16).

uploads the meter reading data to the billing system only once all meters for a particular billing cycle have been read (id. citing Tr. 10, at 1292). Further, the Company argues that because the actual reading of all meters in a billing cycle can take more than one day, it is normal for the billing lag to be more than one day, even for meters read and billed without an intervening weekend lag (id. at 33, citing Tr. 10, at 1292). The Company concludes that the Department should reject the Attorney General's proposed adjustment to the Company's billing lag calculation (id. at 34; Company Reply Brief at 9).

3. Analysis and Findings

If properly designed, lead-lag studies are an appropriate method to determine cash working capital. Lead-lag studies, however, are complex and costly to undertake. Not wanting to require expensive lead-lag studies, the Department has encouraged utilities to consider and offer other cost-effective methods to produce lower working capital requirements than the traditional 45-day convention. D.T.E. 03-40, at 92; D.T.E. 02-24/25, at 55; D.T.E. 98-51, at 15.

In the present case, NEGC conducted a lead-lag study using an outside consultant (Exh. NEGC-JMS at 30).[22] The Company has proposed to apply the results of this study to meet its cash working capital needs, through a purchased gas net lag factor of 26.11 days and a net lag factor of 24.44 days (id.; Exh. NEGC-JMS-2, Sch. D). When we compare the

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[22] Although the lead-lag study was combined with the fixed fee arrangement used for preparing the revenue requirement portion of the rate case, the Company estimated that the total actual cost of the lead-lag study was approximately $11,200 (Tr. 12, at 1297-1298; RR-DPU-60).

normalized cost of preparing the lead-lag study to the effect the lower cash working capital factor has on revenue requirements, we conclude that the Company's decision to perform a lead-lag study was a cost-effective means to determine its working capital needs.[23]

The Department has examined NEGC's lead-lag study. The Company has included purchased gas expense in its cash working capital requirement to develop a composite cash working capital factor (Exh. NEGC-JMS-2, Sch. D). Although NEGC states that it will extract the purchased gas working capital component from the total cash working capital allowance when designing its compliance rates, it is more efficient for cash working capital associated with purchased gas and O&M expenses to be calculated separately (Exh. NEGC-DAH-7, at 17; Tr. 2, at 208-209). Separate calculations would ensure against any overlap between purchased gas working capital and O&M working capital, as well as reduce the probability of errors in the compliance filing. Finally, separate cash working capital computations would be consistent with how the Department has historically treated cash working capital allowances. D.T.E. 02-24/25, at 51; D.P.U. 88-67 (Phase I) at 40-43. Therefore, the Department will determine the appropriate cash working capital components and amounts to be used in the Company's compliance filing.

NEGC has proposed a 3.44-day billing lag, which the Attorney General contends is overstated. We acknowledge that the Company is not able to read all of the meters scheduled

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23 Based on the Company's test year O&M expense of approximately $23.7 million, a one-day decrease in the lead-lag factor produces a reduction of approximately $64,900 to cash working capital requirements, which translates into a decreased revenue requirement of approximately $9,300.

to be read in a particular billing cycle in a single day because of factors such as the need to access inside meters, as well as the need to address billing exceptions such as faulty readings or unusually high or low readings (Tr. 10, at 1292-1293). This delay will produce an increased billing lag. Nonetheless, we fail to see the Company's logic in holding bills for a particular billing cycle until all of the meters for that cycle have been read. This systematic delay only serves to decrease the Company's cash flow and thus increase working capital needs. Similar to how a prepayment of service to an affiliated company represents a gift of working capital to the affiliate and inappropriately increases the regulated company's working capital need, a delay in issuing bills inappropriately increases a company's working capital requirements. See Cambridge Electric Light Company, D.P.U. 92-250, at 20-21 (1993).

The Department has examined the Company's meter reading and billing lag data (Exh. NEGC-JMS-3, WPs D.3.1 through D.3.6). To make the most efficient use of its metering and billing systems, NEGC organizes its meter routes on the basis of 22 cycles per month (id. at WPs D.3.1 through D.3.6; Exh. DPU 3-5). Examination of the meter read dates and corresponding billing dates demonstrate that of the 264 total days when meters are read, the billing lag ranges between one and three days for 143 of the meter reading days, ranges between four and six days for 112 of the meter reading days, and ranges between seven and eight days for nine of the meter reading days (Exh. NEGC-JMS-3, WPs D.3.1 through D.3.6). The Department finds that delays of up to eight days from meter reading to billing is excessive. Therefore, the Department finds it appropriate to reduce the proposed billing lag.

While the Attorney General has proposed a billing lag component of 1.4 days, we find that her simple averaging method fails to account fully for the effects of weekdays and holidays in the billing lag. Based on the Company's testimony that bills can be produced on the next business day (Tr. 7, at 880-881), the Department finds that the maximum billing lag should be three days. There are a total of 304 billing lag days associated with the one to three-day billing lag periods (Exh. NEGC-JMS-3, WPs D.3.1 through D.3.6). This number, divided by the 143 billing days where the billing lag is three days or less, produces a billing lag component of 2.12 days. Accordingly, the Department will reduce the billing lag from 3.44 days to 2.12 days.

Turning to the Company's proposed 0.37-day bank deposit lag, the Department has previously rejected the idea that payment lags should include the time it takes for a check to clear. D.T.E. 02-24/25, at 50; D.P.U. 89-114/90-331/91-80 (Phase One) at 20-24. While the Company urges the Department to reconsider this precedent based on the practices of its payment arrangements, NEGC has provided insufficient evidence to support its claim that payers are no longer required to have the funds in their bank account when the check is written. Moreover, if a bank deposit lag factor is permitted, consistency would justify the use of a check-clearing factor for all other O&M expenses. Calculation of such a factor would be unreasonably complex and add nothing to the overall results of the lead-lag study. Consistent with our precedent, the Department will, therefore, reduce the Company's proposed collection to receipt of funds revenue lag period to zero days.

As a result of these adjustments, NEGC's revenue lag decreases from 65.47 days to 63.78 days. Application of this revenue lag factor to the Company's lead-lag study produces a net lag of 24.42 days for purchased gas expense and a net lag of 21.28 days for other O&M expense. Therefore, the Department will permit NEGC to include a cash working capital allowance for other O&M expense of 21.28 days. The effect of this cash working capital factor on the Company's revenue requirement is provided in the schedules attached to this Order. The purchased gas net lag factor of 24.42 days is to be used by NEGC in calculating the purchased gas working capital recovered via the CGAC.

D. Transfer of Construction Work in Progress to Plant in Service

1. Introduction

As of the end of the test year, NEGC reported a CWIP balance of $195,049 (Exh. NEGC-JMS-3, WP C-7.7). Of this amount, the Company has reclassified $160,992 from CWIP to CCNC and proposes to increase rate base by that same amount (Exhs. NEGC-JMS at 27; NEGC-JMS-3, WP C-7.7; Tr. 7, at 890-892).

2. Positions of the Parties

a. Attorney General

The Attorney General opposes the Company's proposal to include $160,992 in rate base, whether as CCNC or as plant in service (Attorney General Brief at 16-18; Attorney General Reply Brief at 11-12). First, the Attorney General argues that the Company has provided no evidence to demonstrate when or if the projects in question went into service, or how these projects are actually used and useful to its customers (Attorney General Brief at 17;

Attorney General Reply Brief at 12). The Attorney General contends that the limited information provided by NEGC on this point is devoid of anything approaching substantial evidence on which a finding can be made (Attorney General Brief at 18; Attorney General Reply Brief at 11).

Second, the Attorney General argues that NEGC admitted that it reported a zero balance for CCNC in its 2007 annual return and that the $160,992 amount the Company contends was reclassified from CWIP to CCNC was actually booked to Account 107 (CWIP) at the end of test year (Attorney General Brief at 17, citing Exh. AG 1-2, Att. A(2) at 13; Tr. 7, at 895). The Attorney General maintains that, regardless of what account the Company booked these costs in, the evidence establishes that the plant actually represents CWIP and that NEGC did not demonstrate when these projects went into service (id.; Attorney General Reply Brief at 12).

Third, the Attorney General claims that the Company did not produce the original book value, did not adjust its accumulated deferred income taxes accordingly, and failed to record accumulated depreciation for these projects (Attorney General Brief at 17). In sum, the Attorney General contends that the $160,992 the Company reclassified from CWIP to CCNC should remain in Account 107 (CWIP) and, thus, be excluded from rate base (id. at 16-18; Attorney General Reply Brief at 11-12).

b. Company

The Company contends that it provided documentary evidence that fully explains the original book value and accumulated depreciation associated with the plant (Company Brief at 25, citing Exh. NEGC-JMS-3, WP C-7.7; Company Reply Brief at 7-8). The Company argues that the Attorney General's proposed rate base disallowance is inappropriate because, contrary to the Attorney General's opinion, the Company's proposed $160,992 addition to plant in service was the result of an analysis of whether such projects were used and useful during the test year (Company Brief at 24; Company Reply Brief at 7-8). Further, the Company takes issue with the Attorney General's claim that NEGC did not show when the projects went into service, stating NEGC identified the in-service data (Company Brief at 24-25, citing Exh. NEGC-JMS-3, WP C-7.7; Reply Brief at 8).

3. Analysis and Findings

For costs to be included in rate base, the expenditures must be prudently incurred and the resulting plant must be used and useful in providing service to ratepayers. D.P.U. 85-270, at 20. The Department has historically not allowed the inclusion of CWIP in rate base, because unfinished construction cannot provide any service to then-present ratepayers. Oxford Water Company, D.P.U. 1219, at 4 (1983); D.P.U. 906, at 208.

The Attorney General questions whether the proposed plant additions of $160,992 included in rate base by the Company are used and useful, i.e., whether the plant additions were completed and in service at the end of the test year. The Attorney General cites the booking of this plant to CWIP in NEGC's 2007 Annual Return as contradicting the Company's claims that the plant was actually placed into service during 2007 (see Exh. AG 1-2, Att. A(2) at 13; Tr. 7, at 895). The Department's Uniform System of Accounts for Gas Companies ("USOA-Gas Companies"), however, does not dictate ratemaking treatment. The accounting systems prescribed by the Department, including the USOA-Gas Companies codified as 220 C.M.R. §§ 50.00 et seq., are systems whereby costs are sorted and categorized to provide the Department with information on utility operations and aid in the review of utility costs; they do not establish either the reasonableness per se of the reported costs or the ratemaking treatment to be accorded such costs. D.T.E. 03-40, at 103, 208; D.P.U./D.T.E. 97-95, at 77. The in-service status of the additions is the dispositive factor in this matter.[24]

The plant items in question represent several distribution main projects, various types of monitoring equipment, computer hardware, and pipe detection equipment (Exh. NEGC-JMS-3, WP C-7.7). These plant items were placed into service on various dates between May 3, 2007, and December 28, 2007 (id.,WP C-7.7; Tr. 7, at 891). The Department is satisfied that the plant items were in service as of the end of the 2007 test year and do not represent post-test year additions to rate base. D.T.E. 05-27, at 103. The Company has appropriately included $947 in accumulated depreciation associated with this plant by applying the current accrual rate of 3.5 percent to the plant additions over the respective periods that the plant items were in service (Exhs. NEGC-JMS-2, Sch. C-3;

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24 Notwithstanding our findings here, the Department has emphasized the importance of maintaining plant accounts in conformance with the USOA-Gas Companies. D.T.E. 05-27, at 103 n.78. While some minor delay may be expected between the addition of a plant item and its transfer to plant in service for accounting purposes, at least some of this plant appears to have remained in CWIP for as long as seven months after completion (Exh. NEGC-JMS-3, WP C-7.7). As required by the USOA-Gas Companies, the Company is directed to book CCNC to Account 106.

NEGC-JMS-3, WP C-7.7). Therefore, the Department will include the plant additions of $160,992 in rate base, as well as the accumulated depreciation of $947.[25]

E. Contributions in Aid of Construction

1. Introduction

The USOA-Gas Companies requires that CIAC be booked to a separate account which is then used as an offset against a company's plant investment balance when computing rate base for ratemaking purposes (see Exhs. NEGC-JMS at 28; Tr. 7, at 887). Although NEGC's work order system nets CIAC against construction costs, the Company has revised its rate base calculations to recognize the inclusion of CIAC in plant (Tr. 7, at 887-888).[26] Nevertheless, NEGC requests that the Department allow the Company to continue to record and report CIAC as a direct reduction to the related plant account (Exh. NEGC-JMS at 29).[27]

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25 NEGC did not book any accumulated deferred income taxes associated with the CCNC (Exh. DPU 4-7). Therefore, the Department will not adjust the Company's rate base for deferred income taxes.

26 NEGC's revenue requirement schedules remove the effects of CIAC from rate base (RR-DPU-56-A, Schs. B, C). Because CIAC are deducted from plant balances for purposes of computing both rate base and depreciation expense, this adjustment has no effect on the Company's revenue requirement (see Tr. 7, at 888).

27 As part of its filing in D.P.U. 07-46, NEGC stated its intent to transfer the negative CIAC amounts relating to completed plant into the plant in service accounts to offset the cost of construction (see Exh. NEGC-JMS at 28-29). The Department, however, specifically directed the Company to maintain a separate CIAC account. D.P.U. 07-46, at 9.

2. Positions of the Parties

a. Attorney General

The Attorney General contends that the Company has failed to provide any reason for the Department to depart from its precedent with respect to the accounting of CIAC (Attorney General Reply Brief at 15). The Attorney General notes that the Company has not petitioned the Department to adopt the Federal Energy Regulatory Commission ("FERC") accounting system ("FERC USOA") and has, likewise, not sought a waiver from the USOA-Gas Companies (id. citing Tr. 6, at 763-764).

b. Company

In support of its proposal, NEGC maintains that most jurisdictions now require utilities to account for CIAC consistent with the provisions of the FERC USOA (Company Brief at 29). The Company contends that the FERC USOA requires that CIAC be credited against the construction work order and related plant accounts (id.). NEGC argues that adoption of FERC's method of accounting for CIAC would ensure consistency with the treatment accorded by other regulatory jurisdictions and facilitate the proper calculation of depreciation expense for book purposes (id. at 29-30).

3. Analysis and Findings

General Laws c. 164, § 81, requires gas companies to maintain their books and accounts in a manner prescribed by the Department. The need to ensure accounting uniformity, as well as to facilitate the Department's ability to exercise its general supervisory authority over the industries that it regulates, warrants the adoption of a standardized system of accounts for the companies subject to this agency's jurisdiction. Aquaria LLC, D.T.E. 04-77, at 21 (2005); Reclassification of Accounts of Gas and Electric Companies, D.P.U. 4240-A, Introductory Letter (May 19, 1941). The Department has long prescribed its own accounting system for gas companies in the form of the USOA-Gas Companies. 220 C.M.R. § 50.00 et seq.[28]

Notwithstanding what may be the practice by other regulatory bodies, the Company cannot reasonably claim to be burdened by the use of an accounting system that is used by every other Department-regulated gas company.[29] Moreover, the Department's treatment of CIAC for gas companies, including its effects on the calculation of depreciation expense, is the same for Massachusetts water companies, which in most cases are much smaller systems with less technical and financial capabilities than those available to NEGC. See, e.g., Milford Water Company, D.P.U. 84-135, at 32-33 (1985); Hingham Water Company, D.P.U. 1590, at 22-23 (1984). Separate accounts for CIAC provide the accounting transparency that is necessary to understand the effects of CIAC on rate base, depreciation expense, and income taxes. Therefore, in order to ensure uniform accounting treatment among all gas companies, the Department denies the Company's request to book CIAC using the FERC USOA. The

[28] The Department has adopted the FERC USOA for electric companies with several modifications. 220 C.M.R. § 51.01(1). The Department, however, has not adopted the FERC USOA for gas companies. 220 C.M.R. § 50.00 et seq.

[29] The Company has neither petitioned the Department to adopt the FERC USOA for gas companies, nor has it sought a formal waiver of the Department's accounting regulations (see Tr. 6, at 763-764).

Company is again directed to maintain CIAC as a separate account consistent with the Department's USOA-Gas Companies. See D.P.U. 07-46, at 9.

F. Deferred Income Taxes

1. Introduction

NEGC has proposed an accumulated deferred income tax component to rate base of $8,921,937 (Exh. NEGC-JMS-2, Sch. B). While most of the Company's accumulated deferred income taxes have resulted from tax versus book depreciation expense, certain components of the deferred income tax balance are associated with other tax and timing differences; the Company refers to the elements of its deferred income tax computation collectively as temporary rate base differences (id., Sch. B).[30] The sum of these temporary rate base differences, $23,300,959, was then multiplied by NEGC's composite federal and state income tax rate of 38.29 percent to derive the proposed accumulated deferred income tax component (Exh. NEGC-JMS-3, WP B.3).

NEGC's temporary rate base differences include $2,343,970 in taxable CIAC for its Fall River service area and $594,722 in taxable CIAC for its North Attleboro service area (id., WP B.3). These temporary rate base differences result because CIAC are considered taxable income to NEGC, and consequently the Company itself pays the associated income taxes rather than including the tax consequences of the CIAC in the total CIAC to be collected from a

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30 The term "temporary rate base differences" is inapplicable to CIAC because the property financed by CIAC will never be included in rate base. Accordingly, it is a permanent rate base difference.

customer or developer (Exh. DPU 2-2).[31] The Company subsequently recovers these income tax payments by depreciating, for tax purposes, the property financed by CIAC. The inclusion of these deferred income taxes in rate base is designed to defray the money costs associated with the recovery of these taxes over the tax depreciable life of the CIAC-financed property.

2. Positions of the Parties

a. Attorney General

The Attorney General maintains that the Department's precedent regarding the tax consequences of CIAC is well-established, i.e., the additional costs should be borne by the customers responsible for the costs (Attorney General Brief at 22, citing D.T.E. 02-24/25, at 64; citing Riverdale Mills Corporation, D.P.U. 85-130, at 12 (1985); Cooney v. Southern Berkshire Power and Electric Company, D.P.U. 7968 (1947)). According to the Attorney General, the Company's inclusion of taxable CIAC in the deferred income tax calculation serves to reduce the temporary rate base differences component by $2,938,692, which serves to decrease the deferred income tax balance by $1,125,225 (id. at 22 n.17, citing Exh. NEGC-JMS-3, WP B.3).[32] The Attorney General argues that NEGC has burdened its customers with the tax consequences of CIAC (id. at 21). Therefore, the Attorney General proposes that the Department remove the amounts of taxable CIAC from the calculation of accumulated deferred income taxes (id. at 22).

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31 CIAC has been considered taxable income since the passage of the Tax Reform Act of 1986. See D.P.U. 95-118, at 81.

32 A decrease in accumulated deferred income taxes serves to increase the rate base upon which the Company earns its rate of return.

b. Company

NEGC contends that utility companies are required to pay income taxes on CIAC in the year that the contribution was received (Company Brief at 35). According to the Company, CIAC offer a cost-effective way by which to add system load without burdening ratepayers with either additional depreciation expense or a return requirement (Exh. DPU 2-2). Despite these benefits, the Company points out that CIAC are not entirely cost-free to the utility because CIAC are taxable for federal income tax purposes (id.). The Company reasons that all customers receive the benefit of the CIAC deduction in the form of lower rate base and lower required return, and, accordingly, all customers should bear the cost of that benefit (id.). NEGC maintains that requiring a developer or customer to pay the additional tax obligation arising from CIAC is unrealistic and could result in fewer construction projects (id.). Likewise, the Company contends that to require the utility itself to bear the tax consequences of CIAC would be inequitable and serve to unfairly penalize a utility for minimizing construction costs (id.). Therefore, the Company argues that the cost of accumulated deferred income taxes caused by the tax treatment of CIAC should properly be borne by ratepayers as a whole, rather than individual customers or the Company itself (Company Brief at 35 n.14, citing Exh. DPU 2-2).

3. Analysis and Findings

NEGC's accounting treatment of CIAC-related income taxes results in a decrease to the deferred income tax reserve, thereby increasing rate base.[33] Therefore, the Company's CIAC-related income taxes are presently being paid for by ratepayers as a whole, not by the individual customers requiring additional facilities (Exh. DPU 2-2). While we acknowledge the Company's expression of concern for individual customers, NEGC's practice results in the subsidization of certain customers and these additional costs should not be passed through to ratepayers as a whole, whether directly in the form of higher O&M expenses, or indirectly through a higher rate base. All costs of these types of projects should be borne by the customer responsible for those costs. D.T.E. 02-24/25, at 64; D.P.U. 85-130, at 12; D.P.U. 7968.

Therefore, the Department will remove these taxable CIAC balances from NEGC's temporary rate base differences. This adjustment increases the temporary rate base differences from $23,300,959 to $26,239,651 and, therefore, results in a revised deferred income tax balance of $10,047,162. Accordingly, the Company's proposed rate base will be reduced by $1,125,225.

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33 Deferred income taxes associated with CIAC are accounted for in Account 190 (Accumulated Deferred Income Taxes), which offsets accumulated deferred income taxes accounted for in Account 282 (Other Property) and Account 283 (Other).

III. REVENUES

A. Test Year Revenues

The Company is proposing to consolidate the rate structures for the Fall River and North Attleboro service areas (see Exh. NEGC-JDS-3, at 2; see also Section VII.D. below). Under the proposed consolidation, the Fall River rate structure is used for both service areas; thus, modifications were required to the test year revenue allocations as discussed in further detail below. NEGC determined test year base rate revenue by applying the base rates that were in effect each month during the test year to the monthly billing determinants (throughput or bills) for each rate class (Exh. NEGC-DAH at 5). The appropriate billing rates were then applied to these data and the resulting revenues were compared to those reported in the Company's financial records (id.).

For the Fall River service area, the Company apportioned the normalized monthly rate class volumes into appropriate head block and tail block levels for each rate class (id. at 6). From this, the Company developed normalized bill frequency tables for each rate class (id.). The Company then multiplied the resulting head and tail block volumes by the appropriate rates to obtain the normalized throughput volume (id.). The Company added customer charge revenues to the normalized throughput revenues to produce the total normalized test year base rate revenue (id.). NEGC subtracted the normal revenues from the actual test year base rate revenues to determine the Fall River normalization adjustment (id.).

NEGC followed the same steps to produce the North Attleboro normalization adjustment (id.). Because, however, the Company is proposing to move North Attleboro onto the Fall River rate structure, it allocated the North Attleboro throughput and revenue to the appropriate Fall River rate classes (id.). For the normalization adjustment, the Company separated the head and tail block volumes for each North Attleboro rate class (G-0, G-1, G-2, G-3, and G-4) into its Fall River counterpart (G-41, G-42, G-51, G-52, and G-53) and then applied the appropriate North Attleboro head or tail block base rate (id. at 6-7). The Company subtracted the resulting normalized revenue from the test year base rate revenue to determine the North Attleboro normalization adjustment (id. at 7; Exh. NEGC-DAH-4).

Because the cost of its LNG and propane facilities are not reconciled through the gas adjustment factor ("GAF"), it was necessary for the Company to adjust the actual cost level to $2,397,439 to account for the change to normal throughput (Exh. NEGC-DAH at 7). In addition, as a result of the settlement of D.P.U. 07-46, the Company collects a portion of its pension and post-retirement benefits other than pension ("Pension/PBOP") through the local distribution adjustment clause ("LDAC") (id. at 7-8). The Company applied the pension expense factor ("PEF") to the normalized throughput to determine the normalized PEF revenues of $1,621,060 as the test year LDAC revenue (id. at 8). To remove the impact of gas costs that are collected through the GAF, the Company made a revenue adjustment of $5,012,561 which was necessary to bring gas costs and gas revenues into balance (id.).

B. Weather Normalization Adjustment

1. Introduction

Variations from normal weather cause NEGC's throughput and revenues to be higher or lower than what would be expected during a normal year (Exh. NEGC-DAH at 4).

Accordingly, the Company proposes to adjust its test year throughput and revenues for the effect of warmer or colder than normal weather experienced during the test year ("weather normalization adjustment") (id.).

To calculate the weather normalization adjustment, the Company grouped 18 months of billing records by month and aggregated by rate class and billing cycle (Exh. NEGC-JDS-1, at 13). The aggregated data were used to make separate weather normalization calculations by billing month for each rate class and billing cycle group (id.). The Company performed a test using ordinary least squares ("OLS") regression analysis[34] of each rate class and billing cycle group to determine if the group's delivery quantities were correlated with the temperature, measured by effective degree days ("EDDs") (id.).

For each rate class and billing cycle group that was found to have gas consumption that was correlated with temperature, NEGC used the following approach to calculate the weather normalization adjustment. First, the Company calculated the average daily base load by dividing total July and August billed consumption by the total customer days in billing months of July and August (id.). Second, NEGC calculated the average daily heat sensitive load for each billing month by subtracting the average daily base load from the average daily total use

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[34] The OLS regression analysis used the therms per customer per day as the dependent variable and the EDDs per customer per day as the independent variable (Exh. NEGC-JDS-1, at 13-14). The analysis determined the gas consumption of a rate class and billing cycle group to be correlated with temperature if the R2 (multiple coefficient of determination) of the regression was greater than 0.5 (id.). NEGC stated that it selected 0.5 as the R2 cut-off point to identify rate class billing cycle groups whose use of gas was related to weather because that limit requires that the variation in billing month EDDs per day must explain at least 50 percent of the variation in billing month therms per customer per day (Exh. DPU 3-9).

per customer in that billing month (id.). Third, NEGC calculated the actual daily heating increment for each month by dividing the average daily heat sensitive load by the average actual EDDs per day (id.). Fourth, the Company calculated the difference between the 20-year normal and actual weather by subtracting actual average EDDs per day for the billing month from normal average EDDs per day for the billing month (id.). Fifth, the Company calculated the weather normalization adjustment per customer day by multiplying the difference between actual and normal EDDs per day by the actual daily heating increment (id.). Finally, the Company calculated the total weather normalization adjustment by billing month by multiplying the weather normalization adjustment per customer per day times the total number of customer days in the month (id.). No party commented on NEGC's proposed weather normalization adjustment.

2. Analysis and Findings

The Department's standard for weather normalization of test year revenues is well established. See D.T.E. 02-24/25, at 75; D.P.U. 96-50 (Phase I) at 36-39; D.P.U. 93-60, at 75-80; D.P.U. 92-210, at 194. In The Berkshire Gas Company, D.P.U. 1490, at 26 (1983), the Department stated that the calculations used in normalizing revenues "should account for the difference between billing month and calendar month." This principle has two implications. First, the manner in which a company reports its revenues to the Department, whether on a billing-month or calendar-month basis, should be reflected in a company's approach to weather normalization of revenues. Second, regardless of whether a company normalizes its sales for revenue purposes on a calendar or billing-month basis (to match

Department financial reporting requirements), the company must use a consistent set of data to perform the weather normalization (i.e., billing-month sales and billing degree days, or calendar-month sales and calendar degree days).

NEGC's proposed weather normalization adjustment in the instant proceeding is consistent with the Department's standard. See D.T.E. 03-40, at 22-23; D.T.E. 02-24/25, at 75; D.P.U. 96-50 (Phase I) at 36-39; D.P.U. 93-60, at 75-80; D.P.U. 92-210, at 194. NEGC's use of 18 observations to identify all rate class billing cycle groups whose use of gas was related to weather, as measured by EDDs is appropriate in this case in view of the limited purpose of the regression analysis (Exh. DPU 3-9).[35] We find that the Company's method for calculating its weather normalization adjustment is consistent with the Department's precedent. Therefore, the Department approves the Company's weather normalization adjustment.

C. Billing Adjustment

1. Introduction

The Company has proposed to adjust its test year throughput and revenues from a billing month basis to a calendar month basis (Exh. NEGC-DAH at 4). NEGC contends that this is necessary to capture all the throughput and associated revenue that occurred during the test year but had not been billed by the end of the test year ("calendar month adjustment") and to remove all the throughput and associated revenue billed during the test year that had

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[35] The 18 observations include the twelve months of the test year (January through December 2007), the first two months following the test year (January and February 2008) and the four months prior to the test year (September through December 2006) (see Exh. DPU 3-9).

occurred prior to the test year (id.). Further, the Company states that this adjustment ensures that the peak and off-peak throughput and revenue are assigned to the appropriate period (id.).

To calculate the billing adjustment, the Company grouped test year billing determinants, by rate class, by month consisting of: (1) gas delivery quantities to sales and transportation customers; (2) the number of customer bills (or "customer count"); and (3) maximum daily contract quantities ("MDCQs"), which are specific to high annual use, high load factor C&I rate classes G-43 and T-43 (Exh. NEGC-JDS-1, at 2). To derive test year billing determinants, the Company followed the following steps. First, NEGC obtained per books billing month actual delivery quantities, customer counts, revenues, and the MDCQ for rate class T-43 for all customers for September 2006 through March 2008[36] and transferred the billing data to a spreadsheet (id. at 4).[37] Second, the Company analyzed the billing data and made necessary adjustments and corrections to the raw data (id.). Third, NEGC consolidated the billing data by calendar month by rate class and billing cycle group (id.). Fourth, the Company calculated for the test year calendar month actual and weather normalized delivery quantities for each rate class and billing cycle group (id. at 5).[38] Fifth, the Company created an additional field in the billing database for the combined adjustments

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36 NEGC stated it selected September 2006 through March 2008 because this period represents the test year plus the first four months immediately prior to the test year and the first three months following the test year (Exh. DPU 3-4).

37 Separate billing spreadsheets were created for the Fall River and North Attleboro service areas (Exh. NEGC-JDS-1, at 4).

38 A billing cycle group is the group of customers in a rate class whose meters are read on the same day (Exh. DPU 3-5).

related to normal weather and to calendar month usage, and calculated the portion of the rate class and billing cycle weather and calendar month adjustment to be allocated to each customer in that rate class and billing cycle group (id.). Sixth, NEGC used the current rate and reclass rate data fields to prepare (1) test year actual and weather normalized calendar month delivery quantities and actual customer counts aggregated by actual billed rate class using the current rate data field, (2) test year weather actual and weather normalized calendar month delivery quantities[39] and actual customer counts aggregated by the reclass rate data field;[40] (3) test year weather normalized calendar month bill frequency analyses aggregated by end of year rate class using the reclass rate database (id.).[41]

2. Positions of the Parties

The Company contends that its billing determinants were developed consistent with Department precedent (Company Brief at 132, citing Exh. DPU 3-16). NEGC states that the

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[39] The Company states that it calculated calendar month delivery quantities because the Department requires that rates be designed on the basis of calendar month billing determinants given the Department's requirements that (1) rate changes are to be made effective with a calendar date, and (2) each customer's bill in the billing month that new rates become effective is to be calculated on a pro-rated basis to reflect the gas consumption before and after the effective date of the new rates (Exh. NEGC-JDS-1, at 16).

[40] The Company states that approximately 85 Fall River C&I customers were assigned to different rate classes effective October 2007 (Exh. NEGC-JDS-1, at 11-12). For those 85 customers, the rate class recorded in the reclass rate field would be different from the rate class recorded in the rate field for all months prior to October 2007 (id.).

[41] According to the Company, additional schedules were created using the second reclass rate field in the North Attleboro database to produce C&I billing data aggregated by every relevant combination of current North Attleboro C&I rate classification and Fall River C&I rate classification (Exh. NEGC-JDS-1, at 5).

rate case billing determinants also reflect the Company's proposal to change the size of the seasonal head blocks for most rate classes based on customers' current usage patterns (id.). According to NEGC, the block sizes in the Company's currently effective rates, which were last reviewed in 1995, reflect customer usage patterns that are very different than what are currently experienced by the Company (id.). The Company argues that it employed a reasonable process, using detailed and precise data, to determine the proposed block sizes (id. citing Tr. 970-974). No other party commented on the Company's proposed billing adjustment.

3. Analysis and Findings

The method the Company used to determine test year billing determinants and to calculate test year billing adjustments is consistent with Department precedent. See D.P.U. 96-50 (Phase I) at 39-40; D.P.U. 93-60, at 80-83; D.P.U. 92-210, at 194. In D.P.U. 1490, at 194, the Department stated that the calculations used in normalizing revenues should account for the differences between billing month and calendar month. NEGC's test year billing determinants are based on individual billing data for all of the Company's customers (Exh. DPU 3-16). The Company made adjustments for normal weather and for calendar months to derive test year billing determinants (id.). The Company's method also allowed for an exact matching of billing month delivery quantities for customers in a billing cycle group with the billing month EDDs that are associated with that billing cycle (id.). We note that the Company used statistical analyses to identify all billing cycle groups that have temperature sensitive usage and has calculated weather normalization adjustments for each of these billing cycle groups (id.). Finally, the Company's method allowed for an exact matching of delivery quantities for customers in a billing cycle of a rate class with the calendar month that the gas usage occurred. Thus, the combined adjustment by billing cycle group for normal weather and for calendar month usage is allocated to each customer in that billing cycle group, which allowed for precise measurement of weather normalized calendar month head block and tail block delivery quantities, by rate class (id.). Accordingly, we approve the method used to calculate NEGC's billing determinants and the Company's test year billing adjustment.

D. Returned Check Fee

A returned check fee is charged to a customer whose check is returned because of insufficient funds. The Company proposes to increase its returned check fee in both the Fall River and North Attleboro service areas from $10.00 to $15.00 (Exhs. NEGC-DAH at 8; NEGC-DAH-5, at 1; Tr. 2, at 227). The Company states that the primary expenses related to the returned check fee are labor expenses and processing charges (Tr. 2, at 227). Based on the average number of checks returned, NEGC has proposed an increase of $2,946 to its proposed cost of service (Exh. NEGC-JMS-2, Sch. G-13).

NEGC contends that the proposed increase is necessary to recover current costs and to bring the charge into line with the returned check fees of other Massachusetts gas LDCs (Company Brief at 142, citing Exhs. NEGC-JDS-3, at 28; NEGC-DAH at 8; DPU 3-1;

Tr. at 226).[42] No other party commented on the Company's proposed increase to the returned check fee.

Fees for ancillary services such as processing returned checks are intended to reimburse a company for actual costs incurred in providing these particular services. See, e.g., D.P.U. 95-118, at 84; Whitinsville Water Company, D.P.U. 89-67, at 4-5 (1989); Commonwealth Electric Company, D.P.U. 956, at 62 (1982). The Company estimated the cost associated with processing a returned check is between $5.00 and $10.00 (Tr. 2, at 266). The current returned check fee is sufficient to cover this expense. Therefore, the Company will not be permitted to increase its returned check fee to $15.00. Accordingly, the Company's proposed adjustment is denied.

E. Earnings Sharing Mechanism

1. Introduction

NEGC claims that it had a return on equity of negative 7.54 percent in 2007 and, therefore, is entitled to recover an earnings deficiency of $4,110,329 under the terms of an ESM that is part of the Department-approved settlement in D.P.U. 07-46. See D.P.U. 08-64; see also Attorney General Brief at 22, citing D.P.U. 07-46, at Article 2, § 2.10. The Attorney General argues that the Company's test year must be adjusted to reflect any revenues collected by the Company from the proposed ESM rate adjustment (Attorney General Brief at 22, citing D.P.U. 08-64).

42 The returned check fee charged by gas LDCs varies from $4.00 to $15.00, with $10.75 being the average fee (Exh. AG 2-1 Workpapers). The returned check fee charged by electric LDCs varies from $3.00 to $15.00, with $8.80 being the average fee (id.).

The Company argues that if the Department were to adopt the Attorney General's recommendation, the effect would understate significantly the revenue adjustment needed for the Company to recover its approved cost of service in this proceeding (Company Brief at 37). NEGC contends that this is because the ESM rate adjustment operates apart from the setting of base rates and is designed to reimburse the Company for deficient earnings in a prior fiscal period (i.e., calendar year 2007 in the request in D.P.U. 08-64) (id.).

2. Analysis and Findings

The Department adjusts test year revenues for known and measurable changes to recognize the level of revenues that would likely be collected in a normal calendar year. D.T.E. 03-40, at 10. In D.P.U. 08-64-B, the Department rejected NEGC's argument that the ESM rate adjustment works apart from setting base rates and, as such, the Department also found that where the Order issued today in the instant case sets new rates for NEGC at a just and reasonable level as of February 3, 2009, an ESM rate adjustment is not warranted. Therefore, the Attorney General's argument is moot and need not be addressed.

IV. OPERATING AND MAINTENANCE EXPENSES

A. Divestiture of Rhode Island Operations

1. Introduction

Following its mergers and acquisitions of FRG and NAG in September 2000, SUG combined its Rhode Island operations with those of FRG and NAG to form the NEGC business unit (Tr. 1, at 52). All of NEGC's administrative functions were combined and located in its Providence, Rhode Island headquarters serving both the Massachusetts and Rhode Island service areas (id. at 52-60). In August 2006, SUG sold its Rhode Island operations to National Grid but retained its Massachusetts assets (id. at 53-54). Consequently, the Company transferred the administrative functions for the remaining Massachusetts operations to Fall River, including 26 new employees who were either transferred from the Providence offices or newly hired (id. at 52-60; RR-AG-50-A). The test year cost of these new 26 employees was $2,803,311 (RR-AG-50-A, Supp.).

The Attorney General recommends a $2.38 million reduction in the Company's test year expenses to account for what she considers to be SUG's mismanagement and failure to realize savings from its mergers in 2000 (Attorney General Brief at 23-24). According to the Attorney General, this amount is equal to 85 percent of the test year costs of the 26 new employees hired after SUG sold its Rhode Island assets to National Grid (id. at 26, citing RR-AG-50, Supp.).

2. Positions of the Parties

a. Attorney General

The Attorney General claims that the recent and repeated requests for rate increases in base rates by NEGC are the result of SUG's mismanagement of the assets of NEGC and that Massachusetts customers are paying for SUG's failure to keep all operations together with those in Rhode Island (id. at 23-24). The Attorney General states that SUG's purchase of FRG and NAG was accompanied by a promise of lower rates that would result from the economies of scale that a larger corporation would bring, including reduced operating costs, gas costs, and financing costs (id. at 24, citing Southern Union Company/Fall River Gas Company, D.T.E. 00-25, at 10-11, 13-14, 21-22 (2000); Southern Union Company/North Attleboro Gas Company, D.T.E. 00-26, at 10-12, 12-13, 20-21 (2000)).

The Attorney General, however, contends that those promises of lower costs have not been realized. Instead, she claims that the Company: (1) received a total of $4.2 million from two base distribution rate increases during 2007 and 2008, representing a 23 percent increase in rates; (2) requested another $5.5 million base distribution rate increase in the instant case; and (3) proposed a $4.1 million increase from an ESM rate adjustment (id. at 1-2, 25). As a result, the Attorney General asserts that NEGC's customers are facing what could amount to a 74 percent increase in distribution rates over the two plus years since NEGC became a stand-alone division of SUG (id. at 2; Attorney General Reply Brief at 1-2).

The Attorney General contends that the sale of SUG's Rhode Island operations stranded the Company's Massachusetts operations and deprived NEGC of administrative and back office functions, thereby requiring the Company to hire 26 new employees who were either transferred from the Providence office or hired anew to provide necessary administrative functions (Attorney General Brief at 25-26, citing Tr. 1, at 52-60; RR-AG-50-A Supp.). The Attorney General reasons that without the benefit of being able to spread the costs of these new employees over what was a larger company that included all customers in Rhode Island, economies of scale and efficiencies were lost and, consequently, the cost per customer in Massachusetts increased (id. at 25).

The Attorney General claims that prior to that sale and at the time that SUG combined its Rhode Island and Massachusetts operations to form NEGC, the Company had approximately 350,000 customers (id. at 24). Of this total number of customers, 53,000, or approximately 15 percent, were customers of FRG and NAG (id. citing Tr. 1, at 52-53; Exh. NEGC-JMS-3, WP G-29.4).[43] The Attorney General notes that the test year compensation of those 26 new employees, including salary and benefits, was $2.8 million (id. at 26, citing RR-AG-50-A Supp.). The Attorney General argues that these costs would have been shared between Massachusetts and Rhode Island customers before the sale of the Company's Rhode Island operations (id.). Using the number of customers as a basis for cost allocation, the Attorney General asserts that 85 percent of those costs, or $2.38 million is a direct result of SUG's sale of NEGC's Rhode Island operations and, therefore, should not be borne by Massachusetts customers (id.).

The Attorney General argues that the loss of economies of scale, arising from the loss of the Rhode Island operations, caused an increase in back office costs between 2005 and 2007, including: (1) a $1.3 million, or more than 100 percent, increase in customer records and collection expenses; (2) a $0.5 million, or 400 percent, increase in office supplies and expenses; and (3) a $0.7 million, or 400 percent, increase in outside services employed (Attorney General Reply Brief at 19, citing Exh. AG 1-2, Atts. A(1) at 47, lines 5, 19, 21, A(2) at 47, lines 5, 19, 21, B(1) at 47, lines 5, 9, 21, B(2) at 47, lines 5, 19, 21). In addition,

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43 The Attorney General also claims that, at the time when the Rhode Island and Massachusetts operations were combined, all of the Company's administration and back office functions were combined and located in Rhode Island serving both Massachusetts and Rhode Island service territories, leaving the Massachusetts operations with employees who worked on the mains, services, and meters (Attorney General Brief at 24, citing Tr. 1, at 52-60).

the Attorney General notes that the Company's overall cost of providing distribution service has increased by 40 percent in less than two years (Attorney General Brief at 2; Reply Brief at 19). The Attorney General concludes that these increases in costs can only be explained by the total loss of efficiency or the loss of economies of scale associated with the sale of Providence Gas (Attorney General Reply Brief at 19).

The Attorney General claims that her proposed adjustment of $2.38 million represents the annual costs of SUG's mismanagement of NEGC and the direct result of the reverse merger sale of SUG's Rhode Island assets (Attorney General Brief at 26, citing Exh. NEGC-JMS-2, Schs. G-4, G-30). The Attorney General asserts that Massachusetts customers should not be burdened with these costs, while SUG's management and shareholders benefit from the sale (id.).[44]

The Attorney General states that this is the first adjudicated rate case since FRG and NAG were acquired by SUG and, therefore, the Department's first opportunity to review the status of the operational improvements that SUG promised when it received Department permission to acquire these companies in 2000 (Attorney General Reply Brief at 2, citing D.T.E. 00-25). The Attorney General adds that this is also NEGC's first rate case since SUG divested its Rhode Island assets, noting that while the limited scope of G.L. c. 164, § 96 prior

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44 The Attorney General claims that, as the Company continued to reestablish its back office functions in Massachusetts during 2007 and 2008, its customers also suffered from SUG's questionable practices and lack of data in gas supply procurement (Attorney General Brief at 25 n.20, citing New England Gas Company, D.P.U. 08-11, Tr at 139-143 (case pending)). The Attorney General suggests that the Department consider this matter when it determines the appropriate rate of return for the Company in this case (id.).

to 2008 allowed SUG to bypass Department review of the reverse merger, the impacts of this transaction on the remaining Massachusetts customers are subject to regulatory scrutiny in this docket (id.).[45]

b. Company

The Company contends that the employees transferred to NEGC, or newly hired after the sale of SUG's Rhode Island operations, did not result in a net increase in costs to Massachusetts customers (Company Brief at 40). The Company argues that there is no evidence that indicates the presence of or quantifies any net incremental costs associated with the reverse merger (id. at 40 n.15, citing RR-AG-50). The Company contends that the Attorney General's conclusion that cost increases between 2005 and 2007 are the result of loss of economies of scale is without attribution and, therefore, the Department should reject the Attorney General's proposed adjustment (Company Reply Brief at 10).

The Company claims that the Attorney General ignored a number of costs that were previously charged to Massachusetts operations and were eliminated as a result of the sale of the Rhode Island operations (Company Brief at 41). These costs include labor-related costs, management fees, and other costs that, without the sale, the Company contends would have been included in the Massachusetts operations' cost of service on a normalized basis (id.).

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45 The Attorney General notes that prior to the 2008 amendment of G.L. c. 164, § 96, the Department did not have specific authority to approve mergers involving holding companies that were not organized as regulated utilities and were not directly subject to the Department's jurisdiction, even if the holding companies had retail subsidiaries that were subject to Department jurisdiction (Attorney General Reply Brief at 2 n.2, citing Bay State Gas Company/Unitil Corporation, D.P.U. 08-43-A, at 14 (2008)).

Contrary to the Attorney General's claim, the Company argues that the sale of the Rhode Island operations resulted in a reduction of 14.5 full-time employees ("FTEs") from 146 FTEs, under the pre-sale structure, to 131.5 FTEs in 2007 (id.; Company Reply Brief at 9-10). Noting that the 2007 level of FTEs was used to calculate the adjusted payroll dollars in its cost of service, the Company states that the benefits from such a reduction in FTEs are already recognized in the Company's filed cost of service (Company Brief at 41, citing Exh. AG 1-46). The Company also claims that the payroll dollar increase from 2005 to 2008, including pay raises scheduled for 2009, was only 5.5 percent, or an average increase of 1.37 percent per year (id. at 42-43, citing Exh. NEGC-JMS at 10; Company Reply Brief at 2).

The Company disputes the Attorney General's claim that as a result of the sale of its Rhode Island operations, the Massachusetts assets were stranded and its administrative functions reconstituted, resulting in customer costs increases (Company Brief at 44). The Company argues that from a cost of service perspective, the costs of some Rhode Island employees, who supported the Massachusetts operations prior to the sale, were properly charged to the Massachusetts operations (id. at 45). The Company argues that, by seeking to eliminate 100 percent of the cost of the employees who moved from Providence to Massachusetts after the 2006 sale, the Attorney General implicitly assumes that there had been no support provided by the Company's former Providence employees (id.).

The Company also questions the Attorney General's analysis that assumes the savings that resulted from the Company's 2000 merger with SUG would continue in perpetuity (id.).

The Company argues that merger-related savings may not be sufficient to overcome costs increases over time and, therefore, rate increases may be required (id. at 45-46).

3. Analysis and Findings

The issue before the Department is whether the Company, by selling its Rhode Island assets, inappropriately eliminated the economies of scale and cost savings from the 2000 mergers and acquisitions of the former FRG and NAG. The Attorney General claimed that the \$2.38 million proposed reduction in test year expenses represents "the annual cost to Massachusetts customers from Southern Union's mismanagement of NEGC and the sale of the Rhode Island assets without the Massachusetts assets" (Attorney General Brief at 26).[46]

Although the Attorney General has cited a number of Company rate increases after the 2006 sale of SUG's Rhode Island assets, including the 2007 and 2008 increases in base distribution rates pursuant to an approved settlement,[47] the Department is not persuaded that such rate increases arose from the Company's inability to generate the promised cost savings

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[46] There were 27 new employees with a test year cost of \$2,803,311 (RR-AG-50-A). Because one employee worked in the Company's unregulated appliance business, the cost of that employee was removed resulting in a test year regulated cost of \$2,715,475 (id.). Eighty-five percent of this amount is equal to \$2,308,154.

[47] On July 31, 2007, the Department approved a rate settlement, filed by the Company, the Attorney General, and the Low-Income Affordability Network, that provided for among other things, a base distribution rate decrease of \$181,340 for the Fall River division and a base distribution rate increase of \$241,281 for the North Attleboro division both effective on August 1, 2007. D.P.U. 07-46, at 2, 9. In addition, the settlement also provided for a \$2,000,000 base distribution rate increase for the Fall River division effective on April 1, 2008. Id. In approving that settlement, the Department concluded that the settlement "is consistent with both applicable law and the public interest and results in just and reasonable rates" Id. at 9.

from its 2000 mergers and acquisitions because of the reverse merger arising from the sale of SUG's Rhode Island assets. There is no evidence in this proceeding that SUG's decision in 2000 to acquire gas distribution operations in the New England area was the result of mismanagement. Moreover, there is no evidence that SUG's later decision to focus on its gas gathering and transmission operations was anything other than a change in corporate philosophy. In sum, there is no evidence to support the Attorney General's contention of mismanagement on the part of SUG.

In approving the 2000 FRG and SUG merger, the Department noted that absent the merger, FRG, at that time, would have requested a rate increase of approximately $2.0 million. D.T.E. 00-25, at 8, citing Southern Union Company/Fall River Gas Company, D.P.U. 96-60 (1996). The Department found that the merger "would serve to defer some level of rate increases that would otherwise have been borne by Fall River's ratepayers" and concluded that "Fall River's ratepayers would be at least as well off with the merger than they would be absent the merger." Id. at 9, citing D.T.E. 98-31. In the case of the NAG-SUG merger,[48] the Department approved the merger proposal, noting that any future rate changes would be subject to Department review.[49] D.T.E. 00-26, at 8-9.[50]

SUG has also not sought to recover any merger-related costs from the time the mergers were approved in 2000 until after SUG's sale of its Rhode Island assets to National Grid in August 2006. If there were any merger-related costs, those costs were borne by the Company's shareholders.

The Department has examined the Attorney General's proposal in light of the Company's payroll expenses for the period prior to and after the sale of SUG's Rhode Island

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48 On September 6, 2000, the Department approved the merger of FRG and SUG. D.T.E. 00-25, at 33. Under the terms of the merger agreement, FRG merged directly with and into SUG, and SUG, as the surviving corporation, would operate the Fall River service area as a separate division. Id. at 2, 33.

On that same date, the Department approved the merger of NAG, Providence Energy Corporation, and SUG. D.T.E. 00-26, at 29. Under the terms of the merger agreement, NAG merged with and into Providence Energy Corporation, and Providence Energy Corporation merged with and into SUG. SUG, as the surviving corporation, would operate the North Attleboro service area as part of a New England business unit. Id. at 2-3.

49 In both cases, the Department noted that the proposals differed from other merger proposals considered by the Department in that SUG operates as a single utility in multiple jurisdictions. D.T.E. 00-25, at 25; D.T.E. 00-26, at 24. In each case, the Department stated that because the respective service area would remain fully subject to the Department's regulatory jurisdiction under G.L. c. 164, the proposal was consistent with the public interest. D.T.E. 00-25, at 27; D.T.E. 00-26, at 26.

50 In approving the mergers, the Department noted that the Electric Restructuring Act revised the definition of "gas company" and "electric company" set out in G.L. c. 164, § 1, to include non-Massachusetts corporations operating gas or electric utilities within Massachusetts, adding that the Act gives the Department the same jurisdiction over foreign utilities operating in Massachusetts as is currently applied to Massachusetts-chartered corporations. D.T.E. 00-25, at 27; D.T.E. 00-26, at 26.

operations. In 2005, for example, the year before the sale of the Rhode Island operations, the Company's total employee hours, which included overtime hours, for the Massachusetts operations decreased from 321,109 hours to 314,300 hours in 2006 (or a two percent decrease) and to 288,100 hours in 2007 (or an eight percent decrease) for a twelve percent reduction from 2005 to 2007 (Exh. AG 1-46).[51] Included among the 130 employees at the end of 2007, were those 26 newly-hired employees consisting of personnel that were either previously working with NEGC at its Providence headquarters or newly hired to fill in the various functions when NEGC established its administrative offices at 45 North Main Street, in Fall River and other locations for its Massachusetts operations (RR-AG-5; RR-AG-50; Tr. 1, at 53-54).

Although the sale of its Rhode Island assets required the establishment of additional administrative offices for NEGC's Massachusetts operations, those offices and their personnel currently serve the needs of Massachusetts customers and will continue in the future to provide the needed administrative services. Acceptance of the Attorney General's proposal would disallow the recovery from base distribution rates of approximately $2.38 million, equal to 85 percent of the test year costs of the 26 new employees. By way of reference, this

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[51] Based on the Company's annual returns filed with the Department, the total year-end numbers of employees for 2005, 2006, and 2007 for the Fall River division were 126, 132, 130, respectively (Exh. AG 1-2, Atts. (C)(2) at 47, (B)(2) at 47, (A)(2) at 47). The corresponding total number of year-end employees for the North Attleboro division were 4, 4, and 0, respectively, for a combined total of 130 for 2005, 136 for 2006, and 130 for 2007 for the Fall River and North Attleboro operating divisions (id., Atts. (C)(1) at 47, (B)(1) at 47, (A)(1) at 47, (C)(2) at 47, (B)(2) at 47, (A)(2) at 47; see Exh. AG 1-46; Tr. 1, at 53-54).

disallowance would be equivalent to the elimination of approximately 22 NEGC employees, based on current payroll costs, and represents a reduction of approximately 36 percent to the sum of the Company's test year O&M and administrative/general costs (see Exh. NEGC-JMS-2, Sch. G-1). Although the Company is subject to the staffing level requirements of G.L. c. 164, § 1E(b), a disallowance of this magnitude could potentially jeopardize the Company's ability to provide safe and reliable service to its customers.

We will not implement the Attorney General's proposed reverse merger reduction in test year expense of $2.38 million because there is no evidence to support the Attorney General's assertion of mismanagement by SUG. Nonetheless, the Department recognizes that there were some significant Company activities prior to and immediately after SUG's 2006 sale of its Rhode Island assets (Exhs. AG 5-16; AG 5-17; AG 5-18; AG 5-20; AG 5-21; AG 5-23; Tr. 1, at 55). The Attorney General has identified these costs as relating to the following accounts: (1) customer record and collection expense (Account 903); (2) office supplies and expenses (Account 921); and (3) outside services employed (Account 923) (Attorney General Reply Brief at 19). We provide a description of some of these activities below.

During the months leading up to the August 2006 sale of its Rhode Island assets, SUG formed a multi-disciplinary team of employees, both in Rhode Island and Massachusetts, that worked on separating the Massachusetts properties from accounting, computer, billing, and other systems, and to establish the billing, accounting, customer service, information technology, gas supply, and other services that were needed by the resulting standalone NEGC operations in the Fall River and North Attleboro service areas (Tr. 1, at 55).[52] As the Company noted, it undertook an "intensive effort over several months" (id.).

In addition, NEGC established administrative offices at 45 North Main Street in Fall River, acquired additional office space to accommodate people who were being transferred to Fall River, initially leased modular office space at a trailer in its Charles Street facility and "crammed people into tight quarters in other existing facilities," then leased some space at 10 North Main Street (id. at 53-54, 61-62). The Company eventually settled on a plan to consolidate 17 people from four different locations into one administrative office at 45 North Main Street (id.).[53]

Although SUG maintains an in-house call center for its other gas distribution company, Missouri Gas, which also uses an outside call center service for overflow calls, use of this call center was deemed to be impractical due to Missouri Gas' use of a different information system (id. at 56-58; RR-AG-4). Accordingly, the Company had to establish its own outsourced call

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52 For example, in order to ensure the accuracy of billing records, before leaving Providence, the entire billing database of Massachusetts customers was copied onto electronic data storage devices and uploaded to the Company's current billing system (RR-AG-6). Subsequent to the activation of the billing system in the Fall River location, extensive tests were conducted to ensure that the system was operating accurately, including tests on parallel reports on the Fall River and Providence billing systems to check for any inaccuracies between reports (id.).

53 Although the Company hired accountants, information technology staff, regulatory analysts, sales and marketing personnel, and operations staff, including billing personnel and dispatchers, it did not hire gas supply personnel, explaining that gas supply is handled by the gas supply department located in Missouri (Tr. 1, at 58-60, 142-143, 166-167; RR-AG-5).

center and contracted with a company in Pennsylvania to provide such call center services (Tr. 1, at 56).

The combined expense booked to these three accounts for both the Fall River and North Attleboro divisions decreased by 29.07 percent from 2004 to 2005 (Exh. AG 1-2, Atts. (C)(1) at 47, (C)(2) at 47). The combined total for the same expense items, however, increased by 24.95 percent and 39.05 percent for the periods 2005 to 2006 and 2006 to 2007, respectively (Exhs. AG 1-2, Atts. (A)(1) at 47, (A)(2) at 47, (B)(1) at 47, (B)(2) at 47, (C)(1) at 47, (C)(2) at 47). The increase from 2005, the year before SUG sold its Rhode Island assets, to 2007, the year after the sale, was 73.75 percent (Exh. AG 1-2, Atts. (A)(1) at 47, (A)(2) at 47, (C)(1) at 47, (C)(2) at 47). The year-to-year difference in some of the related subaccounts is attributable to changes intended to facilitate improved cost tracking ability (Exhs. AG 5-17; AG 5-19; AG 5-22). Nevertheless, a significant factor behind the overall increase is the sale of SUG's Rhode Island operations in 2006, which resulted in significant expenditures related to the reestablishment of an administrative office in Fall River, along with the establishment of a management team (Exhs. AG- 5-16; AG 5-20; AG 5-22; AG 5-23). This percentage increase from 2005 to 2007 translates to a $1,949,545 increase in costs for those three account items alone.

In the case of the Fall River service area, we note that the total increase for the 2005 to 2007 period was $2,760,345 or 169.62 percent, compared to that of the North Attleboro service area with a corresponding decrease of $810,800 or -79.59 percent (Exh. AG 1-2, Atts. (A)(1) at 47, (A)(2) at 47, (C)(1) at 47, (C)(2) at 47).[54] In contrast, for the 2004 to 2005 period, at least seven months before the August 24, 2006 sale of SUG's Rhode Island operations, the combined costs of those three expense items decreased by 25.69 percent and 33.88 percent for the Fall River and North Attleboro divisions, respectively (Exh. AG 1-2, Atts. (C)(1) at 47, (C)(2) at 47).

The combined increases in costs of these accounts from 2005 to 2007 are significant. The Company has attributed the 2006 sale of SUG's Rhode Island operations as a major factor behind the increase in expenses (Exhs. AG 5-16; AG 5-17; AG 5-18; AG 5-20; AG 5-21; AG 5-23).[55] The Department has reviewed the expenses booked to Account 903, 921, and 923. While certain cost increases can be attributed to the ongoing presence of new administrative facilities and management staff located in Fall River, the Department is persuaded that other expenses booked to these accounts are of a non-recurring nature. Therefore, the Department finds that the test year expenses booked to: (1) Account 903,

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54 Because the administrative functions were established in Fall River, we would expect that those costs would decrease in North Attleboro, except for the costs incurred for customer record and collection expenses (Account 903). See Exh. AG-1-2, Atts. (A)(1) at 47, lines 5, 19, and 21, (A)(2) at 47, lines 5, 19, and 21, (B)(1) at 47, lines 5, 19, and 21, (B)(2) at 47, lines 5, 19, and 21, (C)(1) at 47, lines 5, 19, and 21, (C)(2) at 47, lines 5, 19, and 21. As of the end of 2007, the reported number of employee in the North Attleboro division was zero (id., Att. (A)(1) at 47).

55 NEGC, for example, stated that the sale of the Rhode Island operations necessitated an alternative billing solution for the Fall River and North Attleboro service areas and, accordingly, the Company entered into a contract with Alliance Data Systems to provide the customer billing functions on an on-going basis (Exh. AG 5-16). In addition and as noted above, the Company had to establish its own outsourced call center and contracted with a company in Pennsylvania to provide such call center services (Tr. 1, at 56; RR-AG-4)

customer record and collection expense; (2) Account 921, office supplies and expenses; and (3) Account 923, outside services employed, are not representative of the test year.

Having found that certain of the Company's general and administrative costs are unrepresentative of the level of expense that will occur in the future, the Department must identify the appropriate remedy. The Department recognizes three classes of expense as qualified for rate recovery: (1) annually recurring expenses; (2) periodically recurring expenses; and (3) extraordinary non-recurring expenses. Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 32-33 (1983). Test year expenses which recur on an annual basis are eligible for full inclusion in cost of service, unless the record supports a finding that the level of the expense in the test year is abnormal. If such a finding is made, it is necessary to normalize the expense to recognize the amount that is likely to recur on a normal annual basis. Id. at 33 (1983).

Costs associated with customer records and collection efforts, office administration, and outside services are annually-recurring expenses. As we have found above, however, the test year level of these expenses is abnormal as a result of the 2006 sale of SUG's Rhode Island operations. Therefore, it is necessary to adjust these expenses so that the Company's cost of service includes a normalized level of expense. D.T.E. 03-40, at 250; Boston Gas Company, D.P.U. 96-50-C at 42-43 (1997). The Department finds that a more representative level of administrative and general expense to include in NEGC's cost of service is the average annual administrative and general expense for Accounts 903, 921, and 923 for the years 2004 through 2007 to determine the test year expense for each of these three items that will be recovered in base distribution rates.[56] These adjustments result in a revised expense level of $1,886,783 for customer record and collection expense (Account 903), $1,143,063 for office supplies and expenses (Account 921), and $536,813 for outside services employed (Account 923) giving a total for the three accounts equal to $3,566,659.[57]

The total amount of $3,556,659 represents a decrease of $1,026,443 to test year cost of service. The Department has, however, made a number of adjustments to NEGC's proposed cost of service as filed, including some that affect these accounts. See Section IV., passim. In order to ensure against making a double-adjustment to the Company's cost of service, the Department has examined NEGC's O&M expense on an account-by-account basis, as provided in RR-DPU-56-A, Sch. G-1, in light of our findings on those various cost of service items. Based on our review, the Department concludes that the Company's total proposed net adjustments to Accounts 903, 921, and 923 were a negative $667,503 (Exh. NEGC-JMS-2, Sch. G-2, at 4). Therefore, the Department will reduce the $1,026,443 by $667,503. The Department has also reduced the Company's professional fees booked to Account 923 by an additional $7,780 (Section IV.H. below). Thus, the total required adjustment to Accounts 903, 921, and 923 is $675,283. The difference between the $1,026,443 in disallowed expenses and

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56 Because the annual returns to the Department compares current year data with that of the previous year, the Company's 2005 Annual Return contains data for the year 2004 (Exh. AG 1-2, Att. (C)).

57 We note that in normalizing these three accounts using the four-year average, the test year levels decreased by $1,037,254 for Account 903 and decreased by $379,390 for Account 923. The test year level for Account 921, however, increased by $390,201 for a combined three-account decrease of $1,026,443.

the $675,283 in reductions to Accounts 903, 921, and 923 made elsewhere in this Order is $351,160. Accordingly, the Department reduces the Company's proposed cost of service by an additional $351,160.

B. Payroll Expense

1. Introduction

During the test year, NEGC booked $7,050,181 in union and non-union payroll expense (Exh. NEGC-JMS-2, Sch. G-4). The Company has proposed an overall increase of $282,433 to union and non-union payroll expense (id., Sch. G-4).[58] The Company calculated this proposed increase by first normalizing its test year payroll expense to annualize wage and salary increases granted during the test year, as well as a 3.8 percent non-union pay increase to be implemented in March 2009 and a 3.5 percent union wage increase scheduled for May 2009 (Exh. NEGC-JMS at 9). This produced an annual payroll expense of $7,447,386, representing an increase of $397,204 over test year cost of service (Exh. NEGC-JMS-2, Sch. G-4). The Company then reduced this amount by (1) $36,157 to recognize the fact that a portion of its payroll expense is recoverable through the residential conservation surcharge ("RCS"), and (2) $78,614 in management and human resource salaries allocated to New England Gas Appliance Company ("NE Appliances")[59] (id., Sch. G-4).

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58 Consistent with this adjustment, NEGC has proposed a decrease of $815 to test year payroll tax expense (Exh. NEGC-JMS-2, Sch. G-5).

59 NE Appliances is a wholly-owned subsidiary of SUG engaged in the sale and rental of gas water heaters and conversion burners (Exh. NEGC-JMS at 7; see also Tr. 7, at 911).

In support of its proposed payroll increase, NEGC conducted comparative analyses that examined compensation and benefits expense levels relative to other investor-owned utilities in the northeast, as well as utilities in other market areas where NEGC competes for similarly-skilled employees (Exh. AG 3-6). SUG's corporate human resources/compensation department relied on data from the American Gas Association ("AGA") compensation survey to evaluate the salaries of its distribution utility employees (id., Att. A).

2. Positions of the Parties

a. Attorney General

The Attorney General does not oppose the Company's proposed adjustment to its cost of service for 2009 union pay increases (Attorney General Brief at 36, citing Exh. AG 1-42). The Attorney General concedes that in the case of union employees, the increases are being made according to a binding contract the Company is legally required to honor (id. citing Exh. AG 1-42).

The Attorney General, however, opposes NEGC's proposed adjustment to its cost of service for 2009 non-union employee pay increases (id. at 35, citing Exhs. NEGC-JMS, at 10; NEGC-JMS-2, Sch. G-4). The Attorney General argues that the proposed 3.8 percent increase in non-union pay for 2009 is unreasonable and unwarranted given current economic conditions in the Company's service territory and, therefore, should be rejected (id.).

The Attorney General also asserts that the Company has failed to demonstrate that it has met the Department's standards governing post-test year payroll increases for non-union employees (id.). The Attorney General observes that the Company is proposing to increase its total union and non-union payroll expense by $397,204, representing increases given in 2007 and 2008, as well as increases for 2009 (id. citing Exh. NEGC-JMS-2, Sch. G-4).

The Attorney General contends that the non-union employees have been given what she considers "significant" salary increases of 3.8 percent in 2007 and 2008, which exceed the 3.5 percent annual union wage increases granted during that same period (id. at 36, citing Exh. AG 1-41). The Attorney General notes that there is no contract for non-union employees and, as such, there is no legal requirement to give non-union wage increases (id.). The Attorney General concedes, however, that because NEGC has already provided those non-union increases, the Department should allow the Company to recover them through rates (id.). Nonetheless, the Attorney General claims that the proposed 2009 increase for non-union employees of 3.8 percent is not reasonable and should be rejected (id.).

More specifically, the Attorney General argues that the bleak condition of the current economy demands that customers' distribution rates stay as low as legally possible (id.). The Attorney General contends that although there are many costs, such as pension benefits, that the Company is unable to control, NEGC has control over pay increases for non-union employees and that the customers should not be required to pay for unreasonable increases in these costs (id.). The Attorney General argues that it is inequitable for the Company to be granting significant wage increases to non-union employees when the customers who would have to pay for those increases are not receiving pay increases themselves (id.).

Further, the Attorney General argues that NEGC made no attempt to survey the expected increases in salaries for comparable employees in its own service territory (id. at 37, citing Tr. 10, at 1306). The Attorney General also claims that the salary surveys the Company uses to support its non-union increase provide no evidence to support a wage increase for 2009 (id.). Specifically, the Attorney General alleges that although the Company used national salary surveys as the basis for its proposed 2009 non-union increases, these surveys were based on historical information available as of the beginning of 2008 and were intended to support 2008 wage increases, not projected increases for 2009 (id. citing Exh. AG 3-6; Tr. 10, at 1306). The Attorney General concludes that NEGC's proposed 2009 increase in non-union pay is unsupported by the evidence and unreasonable given the economic conditions for the Company's customers (id. at 37-38).

b. Company

NEGC maintains that it has met the Department's standard for both union and non-union payroll adjustments (Company Brief at 48-49; Company Reply Brief at 14-15). With respect to the proposed union adjustments, NEGC first notes that the union increase is scheduled to occur in May 2009, which is before the midpoint of the first year that new rates will be in effect (Company Brief at 48, citing Exh. NEGC-JMS at 10). Further, the Company maintains that SUG regularly participates in various annual salary surveys and uses the resulting data to assess the competitiveness of salary levels (id. citing Exhs. NEGC-JMS at 10; AG 3-6, Att. A). The Company contends that a review of this industry compensation data confirms the reasonableness of NEGC's proposed union wage increases (id. citing Exhs. NEGC-JMS at 10; AG 3-6, Att. A).

Turning to its non-union employees, NEGC notes that the increase is scheduled to occur in March 2009, which is again before the midpoint of the first year that new rates will be in effect (id. at 49, citing Exh. NEGC-JMS at 10). NEGC cites to an internal memorandum from SUG's director of compensation as evidence of management's commitment to grant a 3.8 percent non-union wage increase in March 2009 (id. citing Exh. NEGC-JMS at 10). Further, the Company maintains that SUG's participation in various annual salary surveys enables NEGC to use the resulting data to assess the competitiveness of non-union salary levels and confirms the reasonableness of NEGC's proposed non-union wage increases (id. citing Exhs. NEGC-JMS at 10; AG 3-6, Att. A).

The Company asserts that SUG's compensation strategy is to set its compensation level for those positions included in the salary surveys at a midrange of the results and then to apply those results in a reasonably consistent manner throughout the rest of the organization (id. at 50, citing Tr. 10, at 1306-1307). NEGC maintains that in view of the results of the survey data and the Company's compensation strategy, a 3.8 percent increase for non-union employees is within the range of reasonableness (id.).

The Company states that the Attorney General has not shown how NEGC's proposed non-union pay increase is inconsistent with the Department's standard of review (id. at 49). NEGC argues that the Attorney General's arguments regarding current economic conditions and a comparison of the Company's proposed payroll increases to the salaries of the Company's customers does not demonstrate that the proposed increase is unreasonable (id.). Moreover, NEGC argues that the Attorney General has selectively interpreted the evidence concerning surveys on compensation for comparable employees in its service territory, contending that it is more important to examine compensation in light of compensation paid by other gas distribution companies in the northeastern United States (id. at 50, citing Tr. 10, at 1307-1308).

Finally, NEGC argues that its proposed 2009 non-union payroll increase is reasonable because the Company offers levels of compensation that it deems necessary to hire and retain skilled and qualified employees, without being the highest-paying firm or the lowest-paying firm (id. at 50-51, citing Tr. 6, at 709). Accordingly, the Company concludes the Department should allow NEGC to include the costs of its proposed 2009 non-union payroll increase in its cost of service (id. at 51; Company Reply Brief at 15).

3. Analysis and Findings

a. Introduction

The Department's standard for union payroll adjustments requires that three conditions be met: (1) the proposed increase must take effect before the midpoint of the first twelve months after the rate increase; (2) the proposed increase must be known and measurable (i.e., based on signed contracts between the union and the company); and (3) the company must demonstrate that the proposed increase is reasonable. D.P.U. 96-50 (Phase I) at 43; D.P.U. 95-40, at 20; D.P.U. 92-250, at 35; Western Massachusetts Electric Company, D.P.U. 86-280-A at 74 (1987).

To recover an increase in non-union wages, a company must demonstrate that: (1) there is an express commitment by management to grant the increase; (2) there is a historical correlation between union and non-union raises; and (3) the non-union increase is reasonable. D.P.U. 96-50 (Phase I) at 42; D.P.U. 95-40, at 21; D.P.U. 1270/1414, at 14. In addition, only non-union salary increases that are scheduled to become effective no later that six months after the date of the Order may be included in rates. Boston Edison Company, D.P.U. 85-266-A/271-A at 107 (1986).

In determining the reasonableness of a company's employee compensation expense, the Department reviews the company's overall employee compensation expense to ensure that its employee compensation decisions result in a minimization of unit-labor costs. D.P.U. 96-50 (Phase I) at 47; D.P.U. 92-250, at 55. This approach ensures and recognizes that the different components (e.g., wages and benefits) are to some extent substitutes for each other and that different combinations of these components may be used to attract and retain employees. The Department also requires companies to demonstrate that they have minimized their total unit-labor cost in a manner that is supported by their overall business strategies. D.P.U. 92-250, at 55. Nonetheless, the individual components of a company's employment compensation package are appropriately left to the discretion of a company's management. Id. at 55-56.

To enable the Department to assess the reasonableness of a company's total employee compensation expense, companies are required to provide comparative analyses of their employee compensation expenses. D.P.U. 96-50 (Phase I) at 47. Both current and total compensation expense levels and proposed increases should be examined in relation to other New England investor-owned utilities and to companies in a utility's service territory that compete for similarly skilled employees. D.P.U. 96-50 (Phase I) at 47; D.P.U. 92-250, at 56; Bay State Gas Company, D.P.U. 92-111, at 102-103 (1992); Massachusetts Electric Company, D.P.U. 92-78, at 25-26 (1992).

b. Union Payroll Increase

With respect to the Company's union payroll increases, the proposed adjustments appropriately include only those increases that have been granted or will be granted before the midpoint of the first twelve months after the Department's Order in this proceeding (Exhs. NEGC-JMS at 10; AG 1-42).[60] Also, the union payroll increases are based on a signed collective bargaining agreement and, therefore, are known and measurable (Exh. AG 1-42). Finally, NEGC's comparative analyses of compensation levels for other investor-owned utilities in the northeast and compensation data from the AGA demonstrate that the hourly rates paid to NEGC's union employees are reasonable because they are comparable to the average hourly rates of other gas and electric utilities in New England and New York (Exhs. NEGC-JMS at 10-11; AG 3-6-A).

Having found that the proposed union wage increases (1) take effect before the midpoint of the first twelve months after the rate increase, (2) are based on collective bargaining increases for May 2009 and, therefore, are known and measurable, and (3) are

60 The Company states that the midpoint of the first year that the new rates will be in effect is July 1, 2009 (Exh. NEGC-JMS at 10). As new rates will go into effect pursuant to this Order on February 2, 2009, however, the correct date is August 1, 2009.

reasonable in amount, the Department will allow NEGC to adjust its test year cost of service for the union payroll increases.

c. Non-Union Payroll Increases

NEGC has provided satisfactory evidence that non-union increases are granted on a regular basis in the spring of each year and that the Company has expressly committed to granting a 3.8 percent non-union wage increase in March 2009 (Exhs. NEGC-JMS-3, WP G-4.14; AG 1-41). Accordingly, with respect to the Company's non-union payroll increases, the proposed adjustments appropriately include only those increases that have been granted or will be granted before the midpoint of the first twelve months after the Department's Order in this proceeding (Exh. NEGC-JMS at 10).

To address the requirement that there be a historical correlation between union and non-union wages, the Department notes that between 1999 and 2008, annual union wage increases were between 2.0 percent and 5.5 percent and non-union increases were between 3.0 percent and 3.5 percent (Exh. AG 1-41). Between 2003 and 2008, union wage increases were between 3.0 percent and 3.5 percent and non-union increases were between 2.0 percent and 5.5 percent (Exhs. NEGC-JMS at 10; AG 1-41). Finally, for the years 2007 and 2008, union wages increases were 3.5 percent each year, while non-union increases were 3.8 percent for both years (Exhs. NEGC-JMS at 10; AG 1-41). Therefore, the Department finds that a sufficient correlation exists between union and non-union wage increases. Fitchburg Gas and Electric Light Company, D.P.U. 07-71, at 76 (2008); Essex County Gas Company, D.P.U. 87-59-A at 18 (1988).

With respect to a demonstration of the reasonableness of the proposed non-union salary increase, SUG regularly participates in various annual salary surveys and uses the resulting data to assess the competitiveness of salary levels (Exhs. NEGC-JMS at 10; AG 3-6, Att. A). These surveys include the AGA Compensation Survey, Mercer Total Compensation Survey for Energy Sector, Hay Energy Survey, Towers Perrin US Energy Services Databases for Middle Management, Professional and Executive, and Salary.com (Exhs. NEGC-JMS at 10-11; AG 3-6, Att. A). The Attorney General alleges that these salary surveys are based on historic data and, thus, provide no evidentiary support as to the reasonableness of the Company's 2009 non-union salary increases. This lack of foreknowledge about future events, however, is unavoidable and inherent in salary surveys of any type. The purpose of salary surveys are to provide subscribers with sufficient information to both assess their current compensation structures and make informed decisions about future compensation based on conditions that are known or can be reasonably anticipated at the time the surveys are conducted. Other factors, such as a company's own financial position and prevailing economic conditions, must be considered in determining the level of compensation to be paid. The Attorney General's criticism of the salary studies go to their evidentiary weight. In this case, the Department will weigh the salary surveys appropriately in determining the reasonableness of NEGC's non-union payroll increase. See D.T.E. 02-24/25, at 94.

The Attorney General identifies current economic conditions and the Company's lack of any comparison data between NEGC's proposed payroll increases and pay increases of its own customers as further evidence that the proposed non-union salary increases are unreasonable.

The Department is aware of prevailing economic conditions, particularly of those in the Company's service territory. Nevertheless, we note that the rates being set in this proceeding are likely to be in effect for several years. Moreover, utilities must remain competitive in attracting and retaining skilled employees in order to meet their public service obligations. Therefore, we are also obligated to consider what reasonable compensation rates may be on a going-forward basis, despite current economic conditions.

Concerning the lack of comparison data, NEGC did not provide a salary survey specific to its own service territory. Instead, NEGC places greater emphasis on its own historic compensation rates and that of other gas LDCs in the northeast over pay increases being granted by other companies within its service territory (Tr. 10, at 1306-1307). The lack of service territory-specific survey data has not necessarily precluded the recovery of payroll increases. Blackstone Gas Company, D.T.E. 01-50, at 10 (2001); D.P.U. 95-118, at 95. Nevertheless, to weigh the reasonableness of proposed salary increases, both current and total compensation expense levels and proposed increases should be examined in relation to other New England investor-owned utilities and to companies in a utility's service territory that compete for similarly-skilled workers. See The Berkshire Gas Company, D.T.E. 01-56, at 56 (2002); D.P.U. 96-50 (Phase I) at 47. While we recognize the potential difficulty associated with collecting wage and salary data specific to a company's service territory, data of this type serve as an additional measure of the reasonableness of the results of utility-specific salary surveys. See D.P.U. 05-27, at 110.[61] Accordingly, going forward, companies must provide salary data specific to their own service territories, as an additional means for the Department to evaluate the reasonableness of compensation expense.[62]

As noted previously, SUG regularly participates in various annual national salary surveys and uses the resulting data to assess the competitiveness of salary levels (Exhs. NEGC-JMS at 10; AG 3-6, Att. A). Further, the Company has demonstrated that, including the increase for 2009, its non-union compensation levels are within the average compensation ranges of comparable positions in the northeastern United States gas distribution industry (Exh. AG 3-6). Despite the lack of service territory-specific compensation data, the Department finds that NEGC's review of industry compensation data is sufficient to confirm the reasonableness of the Company's salary levels. See D.P.U. 05-27, at 109; D.T.E. 02-24/25, at 94. Having found above that the proposed non-union wage increases (1) are known and measurable, (2) indicate a historical correlation between union and non-union wage increases, and (3) are reasonable, the Department will allow the Company to adjust its test year cost of service for the non-union payroll increases. Accordingly, the Department will increase NEGC's test year cost of service by $282,433.

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61 This type of comparative information has been provided by companies much smaller than NEGC. See, e.g., Milford Water Company, D.P.U. 92-101, at 30 (1992).

62 Because of the considerable range in size and sophistication of Department-regulated companies, we decline to impose a specific requirement as to the form in which this information must be provided.

C. SUG Corporate Compensation

1. Introduction

a. SUG Corporate Allocations

In addition to direct Company union and non-union payroll expense, NEGC is allocated a portion of SUG's corporate expense, which includes compensation paid to SUG's employees and top executives (Exh. AG 1-89, Att. A (Rev.)). During the test year, SUG booked $57,062,898 in corporate operating expense and $1,577,625 in corporate depreciation expense, of which $1,182,647 in operating expense and $41,016 in depreciation expense was allocated to NEGC (Exh. NEGC-JMS-3, WP G-16.2).[63]

The Company made two sets of adjustments to its allocated SUG corporate expense. The first adjustment was a reallocation of costs between NEGC's Fall River and North Attleboro service areas to correct the total pool of allocable SUG corporate costs, producing a net increase of $80,109 in NEGC's allocated share of operating expense and an increase of $433 in depreciation expense (id., WP G-16.2). Then, the Company proposed to

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63 According to the Company, any costs incurred at the SUG corporate level in relation to a SUG business unit, division, or subsidiary are directly assigned to the particular business unit (Exh. NEGC-JMS at 17). Other corporate costs incurred on a combined basis for all SUG business units are allocated among the business units through "causal pool" factors that are derived through a three-part weighted average of each business unit's investment, margin, and expenses (Exh. AG 1-28, Att. E). During the test year, NEGC was allocated 2.61 percent of SUG's corporate costs (Exh. AG 1-89-A (Rev.); RR-AG-17-A). Of this amount, approximately 17.74 percent was capitalized and 82.58 percent was booked to expense (RR-AG-17-A). Consequently, only about 2.16 percent (2.61 percent x 82.58 percent) of SUG's total corporate expense is booked as an expense by the Company. None of the parties in this proceeding commented on the SUG corporate allocation formula.

eliminate $125,979 representing its allocated portion of charges related to two SUG corporate jets, a New York office, stock options, and a non-corporate supplemental retirement plan, because it did not consider these costs to be essential to the provision of distribution service in Massachusetts (id., WP G-16.2; Exhs. AG 1-54; AG 3-20; AG 3-21; AG 3-22; AG 3-23). These adjustments resulted in a pro forma management fee of $1,178,226, consisting of $1,136,777 in operating expenses and $41,449 in depreciation expense (Exh. NEGC-JMS-3, WP G-16.2). NEGC then added $232,130 in expenses related to administrative support from Missouri Gas and subtracted $130 in expenses related to lobbying activities by the AGA (id., Sch. G-16). The net effect of these adjustments resulted in a proposed increase in corporate management fees of $186,563, consisting of $186,130 in operating expense and $433 in depreciation expense (id., Sch. G-16).[64]

b. Executive Base Compensation

NEGC's corporate management fees include compensation paid to SUG's officers with the rank of vice president or above, as well as managers with annual salaries in excess of $175,000 ("executive officers") (RR-DPU-21, Att. A at 16). In 2007, SUG's top-paid executives were: (1) George Lindemann, chairman of the board, president, and chief executive officer, who received total compensation of $3,646,608; (2) Eric Herschmann,

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64 On November 12, 2008, the Company submitted a supplemental response to Record Request DPU-56, consisting of workpapers in support of its updated revenue requirement analysis (RR-DPU-56-C). This filing, however, reports an offset for administrative support from Missouri Gas of $232,130, a decrease of $1,585 from the information provided in Record Request DPU-56-A. The Department accepts NEGC's revised Missouri Gas administrative support expense and will reduce the Company's proposed cost of service by $1,585.

senior executive vice president, who received total compensation of $2,935,423; (3) Robert Bond, senior vice president of pipeline operations, who received total compensation of $1,322,753; (4) Monica Gaudiosi, senior vice president and general counsel, who received total compensation of $1,002,599; and (5) Richard Marshall, senior vice president and chief financial officer, who received total compensation of $742,637 (id., Att. A at 26).

SUG's executive officers' compensation includes salaries, bonuses, stock awards, option awards, a non-equity incentive plan, and non-qualified deferred compensation earnings (id., Att. A at 26). Of these compensation components, NEGC is allocated only a portion of executive base salaries and non-equity incentive compensation (Exhs. NEGC-JMS-3, WP G-16.3; AG 1-2, Att. (E); Tr. 5, at 654-655; RR-AG-17, Att. A). During the test year, the base compensation for SUG's executive officers was $3,213,255 (RR-DPU-21, Att. A at 26). Therefore, based on NEGC's share of SUG corporate expense as described above of 2.16 percent booked to expense, the Company's share of executive base pay during the test year was $69,406 (id., Att. A at 26; RR-AG-17, Att. A).

c. Corporate Incentive Compensation

During the test year, NEGC booked $160,642 representing NEGC's allocated share of $7,437,139 in incentive compensation expense paid to (1) SUG's corporate employees under SUG's Annual Incentive Plan, and (2) SUG's president and senior executive vice president under SUG's Amended Bonus Plan (Exh. AG 1-36(B) at Att. 1; RR-AG-17-A).[65] The Annual

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[65] During the test year, NEGC booked $281,476 in incentive compensation expense for direct Company employees (Exh. NEGC-JMS-2, Sch. G-6; RR-AG-17-A). No party (continued...)

Incentive Plan and Amended Bonus Plan are considered non-equity incentive compensation (RR-DPU-21, Att. A at 25). Under SUG's Annual Incentive Plan, SUG's Compensation Committee approves separate annual financial performance thresholds for eligible corporate employees (id., Att. A at 21). The financial performance thresholds include an earnings per share ("EPS") based metric (id., Att. A at 21).

Incentives are funded such that if 90 percent of the performance goal is met, the amount of the incentive payment is equal to 50 percent of its target level (id., Att. A at 21). Results in excess of the performance target trigger a maximum funding of 120 percent (id., Att. A at 21). During 2007, eligible employees achieved between 30 percent and 120 percent of their target goals (id., Att. A at 21).

In addition to the Annual Incentive Plan, SUG's president and senior executive vice president participate in an Amended Bonus Plan (id., Att. A at 22). Under the Amended Bonus Plan, bonus payments are based on the achievement of a consolidated net income goal (id., Att. A at 22). The Compensation Committee is also given discretion to approve, disapprove, or lower a bonus award, even if the consolidated net income goal is achieved, based on certain strategic, operational, and financial considerations (id., Att. A at 22).

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65 (…continued) raised direct Company employee incentive compensation as an issue and, therefore, it is not discussed here.

2. Positions of the Parties

a. Attorney General

The Attorney General notes that SUG's total compensation increased by more than 27 percent over the test year (Attorney General Reply Brief at 26-27). The Attorney General contends that this increase has produced no discernable benefit to NEGC's customers and, thus, warrants the exclusion of all of SUG's corporate compensation expense, including base pay, from the Company's cost of service (id. at 27).

Further, the Attorney General opposes the inclusion of any incentive compensation in NEGC's cost of service (Attorney General Brief at 28). The Attorney General states the test year incentive compensation expense of approximately $7.4 million paid to SUG employees represents an increase of more than 132 percent over the previous year and more than 86 percent over the average of the previous two years (id. at 27, citing Exh. AG 1-36(B) at 1-3). By way of comparison, the Attorney General notes that NEGC's own payroll expense has increased over that same period by only 9.1 percent (id. at 27-28). The Attorney General claims that most of the increase in SUG's total compensation expense is attributable to incentive compensation (Attorney General Reply Brief at 27, citing Exh. AG 1-36(B) at 1-3).

The Attorney General states that the Company did not attempt to justify this increase in incentive pay or indicate any reason why NEGC's distribution customers should be paying for those increased amounts (Attorney General Brief at 28; Attorney General Reply Brief at 26). The Attorney General reasons that SUG's regular pay increases should have more than compensated corporate employees without the need for additional incentive compensation payments (Attorney General Brief at 28). The Attorney General further asserts that this increase has produced no discernable improvement in management or any other service (Attorney General Reply Brief at 27). Based on her analysis, the Attorney General concludes that SUG's increase in incentive compensation during the test year was unreasonable and should be denied (Attorney General Brief at 28, citing D.P.U. 96-50 (Phase I) at 42; D.P.U. 95-40, at 21; D.P.U. 1270/1414, at 14; Attorney General Reply Brief at 27). The Attorney General, therefore, proposes that the Department limit SUG's incentive compensation expense to $3,205,281, representing incentive compensation paid during 2006 (Attorney General Brief at 28).

b. Local 431

Local 431 argues that the Company's ratepayers are burdened with the cost of excessive executive compensation (Local 431 Brief at 17). Local 431 states that according to Sandell Asset Management Corporation, SUG's largest shareholder, SUG has provided "outsized compensation" to its executives and its board of directors is too closely tied to management (id. citing Exh. UWUA-1, at 15). To the extent these claims are valid, Local 431 argues that NEGC's ratepayers are inappropriately burdened by their allocated share of this excessive compensation (id.).

Local 431 asserts that it appears there is no oversight to prevent excessive compensation and that NEGC's chief operating officer appeared to be unconcerned with this issue (id. at 18, citing Tr. 1, at 116).[66] Local 431 argues that the Department cannot rely on SUG's board of directors or the Company's chief operating officer to protect NEGC's ratepayers from excessive compensation (id. at 19). Local 431 argues, therefore, that the Department must protect ratepayers from any excessive compensation costs and urges the Department to adopt the Attorney General's recommendation that an audit be conducted of NEGC (id. citing Exh. AG-FWR, at 6-7).[67]

c. Company

The Company maintains that the level of overall compensation paid to SUG corporate employees, including executive officers, is reasonable (Company Brief at 58-59). Therefore, NEGC concludes that no adjustment to cost of service is warranted (id. at 59).

In defense of its proposed executive compensation expense, NEGC notes that the Attorney General's proposed reduction of $4,231,858 represents the total corporate incentive compensation and not just the portion that would be allocated to NEGC (id. at 56). The Company contends that the correct amount of incentive compensation booked to expense by NEGC during the test year was $442,118, consisting of $160,642 in SUG corporate incentive pay and $281,476 in direct Company incentive pay (id. at 56-57, 60).

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66 Local 431 states that SUG's chief executive officer owns over $100 million in SUG stock and that NEGC's chief operating officer testified it is not his role to form any opinion whether the level of compensation paid to SUG's top executives is excessive (Local 431 Brief at 18, citing Exh. UWUA-2; Tr. 1 at 115).

67 On November 12, 2008, the Attorney General petitioned the Department to commence an audit of NEGC; this petition has been docketed as D.P.U. 08-110.

The Company states that with respect to SUG's corporate incentive pay, the information provided in SUG's 2007 proxy statement demonstrates that the level of incentive compensation for SUG's corporate management is reasonable (id. at 57). Specifically, the Company explains that the majority of the increase in incentive compensation that occurred during 2007 relates to the compensation of SUG's president and senior executive vice president and that the combined salaries and incentive payments for other SUG employees has remained relatively flat over the past three years (id. at 58). In fact, the Company claims that the 2007 level of total compensation for all other corporate employees is actually slightly less than the 2005 level ($14,389,987 versus $14,507,093) (id. citing Exh. AG 1-2, Atts. (E)(3) at 26; (E)(1) at 27). The Company argues that, at a minimum, the Department should find that the incentive compensation for SUG employees other than the president and senior executive vice president is reasonable and that no adjustment to costs allocable to the Company is required for this portion of incentive compensation expense (id. at 58-59).

The Company states that while SUG's president received $2 million of non-equity incentive compensation in 2007 as compared to $750,000 in 2006, in fact his total compensation of all types fell between 2006 and 2007 from $10,843,335 to $3,646,608 (id. at 59). Concerning SUG's senior executive vice president, the Company states that this position was newly-created in 2007 and, therefore, increased SUG's overall incentive compensation expense level (id. at 59-60, citing Tr. 4, at 660). The Company states that the levels of compensation for SUG's president and senior executive vice percent (1) are reasonable and within appropriate benchmark ranges for similar executives of similarly-sized companies, (2) were determined by an independent committee of the board of directors, and (3) were developed based on data provided by an independent executive compensation specialist (id. at 60, citing Exh. AG 1-2, Att. (E)(3) at 19).

3. Analysis and Findings

a. Allocation Factors

As noted in Section I, above, the Company is not an affiliate of SUG, but rather an operating division of SUG (Exh. AG 1-98). Notwithstanding the distinction between an operating division of a single company and a subsidiary of a holding company, SUG allocates its corporate charges among its operating divisions in much the same manner as a holding company would among its respective subsidiaries (Exh. NEGC-JMS-2, Sch. G-16; RR-AG-17, Att. A). Further, NEGC's direct testimony concerning the allocation of executive compensation demonstrates the similarity of this allocation with its proposed adjustments to SUG's management fees (Exh. NEGC-JMS at 17). The parties raised no objections regarding the allocator that NEGC used. The Department has examined the allocation method used by SUG and finds it to be reasonable. Accordingly, the Department approves of the Company's proposed allocation factors.

b. Compensation Structure

SUG pays a large proportion of its overall compensation for executive officers and other SUG corporate employees on an incentive basis. During the test year, total incentive compensation expense paid to SUG corporate employees of $7,437,139 represented approximately 58 percent of the total base payroll expense of $12,802,846 (Exh. AG 1-36(B)

Att. at 1; Tr. at 661-665). The Department recognizes that different components of employee compensation are, to a certain extent, substitutable for one another. D.P.U. 92-250, at 55-56. Provided the goals are appropriate, a compensation plan that places greater emphasis on incentive compensation may be reasonable. D.T.E. 03-40, at 130. The specific goals of SUG's Annual Incentive Plan and Amended Bonus Plan are discussed below.

c. Incentive Compensation

The Department has traditionally allowed incentive compensation expenses to be included in utilities' cost of service so long as they are (1) reasonably designed to encourage good employee performance, and (2) reasonable in amount. Massachusetts Electric Company, D.P.U. 89-194/195, at 34 (1990). In order for an incentive plan to be reasonable in design, it must both encourage good employee performance and result in benefits to ratepayers. D.T.E. 03-40, at 124; D.P.U. 93-60, at 99. Benefits to ratepayers may be demonstrated by a showing that the selected performance goals are reasonably designed to provide a direct benefit to ratepayers that rewards management incentives and does not penalize employees for events beyond the company's control. D.T.E. 02-24/25, at 101. As a rule, to the extent that a company's employee-performance standard is based on the job performance of the individual employee, the incentive plan is deemed to reasonably encourage good employee performance. Id. at 101-102. To the extent that the incentive compensation is tied only to financial performance, the benefit to ratepayers is unclear. D.P.U. 89-194/195, at 34. The presence of financial performance measures in an incentive plan, however, would not necessarily warrant exclusion of the incentive compensation, because the Department has accepted incentive plans that rely on the achievement of financial goals to determine employee eligibility, with other factors used to determine the actual level of compensation an employee may receive. D.P.U. 02-24/25, at 101; D.P.U. 89-194/195, at 34.

If the incentive plan relies on performance measures that are unrelated to the utility operation (such as the performance of non-regulated operations), there is no obvious or direct benefit to ratepayers and, therefore, the Department will remove that portion of the incentive payment from cost of service. D.T.E. 02-24/25, at 102. The Department has also disallowed incentive compensation for senior management if the company's management failed to show themselves worthy of bonuses. D.P.U. 85-266-A/271-A at 110-111.

First, the Department must determine whether SUG's corporate incentive compensation programs are reasonable in design (i.e., whether the programs encourage good employee performance and result in benefits to ratepayers). While the Company has provided the Department with general information regarding the design of its corporate incentive compensation programs and examples of performance criteria under the programs, it has not provided the specific performance goals that each employee who participated in the executive compensation programs was required to meet (see RR-DPU-21, Att. A at 17, 21-22). Accordingly, the Department cannot determine if the individual performance goals are appropriately tailored to the responsibilities of eligible executive employees or encourage good employee performance. Further, the Department has questioned the benefit of incentive compensation plans based solely on a company's financial performance. D.P.U. 07-71, at 83; see also D.T.E. 03-40, at 126. SUG's EPS is used as a threshold factor in SUG's Annual

Incentive Plan, a metric which the Company states is intended to align employee and shareholder interests (RR-DPU-21, Att. A at 21). While it appears that other strategic and operational targets were included as part of SUG's Amended Bonus Plan, the Company has not provided the Department with sufficient information about the specific targets to determine whether they are designed to encourage aspects of SUG's operations that would provide benefits to NEGC's ratepayers (id., Att. A at 22). Further, while SUG added certain customer service and operational metrics as performance objectives for direct NEGC employees in 2008, it does not appear that these same metrics were included as performance objectives for SUG corporate employees under the Annual Incentive Plan (id., Att. A at 21). Even if such metrics were included as measures of corporate employee performance, the Company has failed to provide any detail regarding the nature of such operational and customer service metrics sufficient to allow the Department to consider whether they will result in benefits to NEGC ratepayers (id., Att. A at 21).

Based on the above, the Department finds that the Company has failed to demonstrate that the Annual Incentive Plan for SUG's corporate employees and the Amended Bonus Plan for SUG's president and senior executive vice president are reasonably designed to encourage good employee performance and will result in benefits to NEGC's ratepayers. We need not reach the issue of whether the payments made under SUG's Annual Incentive Plan and Amended Bonus Plan are reasonable in amount. The Department will exclude NEGC's allocated share of payments made under SUG's Annual Incentive Plan and Amended Bonus

Plan the Company's cost of service. Accordingly, the Company's proposed cost of service will be reduced by $162,227.

d. Total Executive Compensation

SUG's human resource consultant reviewed SUG's executive compensation structure. The consultant concluded that the compensation for SUG's senior executives, including all of its executive officers, fell within the middle half of a range of total compensation based on both a peer group of energy companies comparable to SUG and non-utility companies with revenues comparable to those of SUG (RR-DPU-21, Att. A at 19). Although SUG's senior executive vice president was found to have a total compensation package that was significantly higher than the benchmarking survey results, the benchmarked positions used to compare this individual's position did not adequately recognize the difference in overall responsibilities and function (id., Att. A at 19). For these reasons, and with the exception of $160,642 in SUG corporate incentive pay allocated to NEGC as discussed in the section above, the Department finds that the Company has demonstrated that remainder of SUG's overall executive compensation expense allocated to NEGC reasonable (id., Att. A at 19).

D. Capitalized Employee Benefits

1. Introduction

During the test year, NEGC booked $4,570,472 in employee benefits expense, representing 401K expense, incentive compensation[68], sick leave, various medical insurance coverage, and pension/PBOB (Exh. NEGC-JMS-2, Sch. G-6). The Company has proposed a

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68 Incentive compensation is addressed above in Section IV.C.

reduction of $1,017,646 for this expense (RR-DPU-56-A, Sch. G-6). The Company determined this amount by first updating its various benefit premiums to recognize current costs, which totalled $4,082,287 (Exh. NEGC-JMS at 12-13). NEGC then reduced this amount by $96,467 representing benefits associated with NE Appliance employees (id.; RR-DPU-56-A, Sch. G-6). Of the net amount of $3,985,820, (1) $86,563 was associated with Company employees charging their time to NE Appliances and additional allocations to the appliance subsidiary, (2) $7,864 was allocated to the RCS program, and (3) $338,566 was capitalized, producing a net benefits expense of $3,552,827 (Exh. NEGC-JMS-2, Sch. G-6).[69] NEGC determines the level of employee benefits to be capitalized each month by multiplying the current month's capitalized labor expense by a "benefit per labor dollar" ratio (Exh. AG 6-6). The benefit per labor dollar ratio is calculated each month by dividing the prior twelve month cumulative total benefits by the prior twelve months' cumulative total payroll (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company failed to capitalize an appropriate amount of employee benefits costs (Attorney General Brief at 31). According to the Attorney General, the USOA-Gas Companies requires the wages and salaries associated with an employee engaged in capital projects to be proportionately assigned to that hour, capitalized,

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[69] Pursuant to the USOA-Gas Companies, payroll and benefit expenses associated with construction are added to the cost of the plant, and recovered over the life of the plant. 220 C.M.R. § 50.00 et seq. (Gas Plant Instructions 3 and 4).

and included in the cost of project (id. at 32, citing Tr. 5, at 651). The Attorney General contends, however, that the Company capitalized 8.74 percent of its employee wages and salaries costs, yet only capitalized 5.401 percent of its employee benefits costs (id. citing Exh. AG 1-40).

The Attorney General states that NEGC's benefits capitalization approach improperly combines pre-test year and test year activity to develop the benefits per labor dollar ratio, and thus distorts the capitalization ratio (id. at 32-33). The Attorney General also notes that, over time, the benefits capitalization ratio will equal the wage and salaries capitalization ratio (id. at 33). The Attorney General proposes that the Department reduce the Company's proposed cost of service by applying the same 8.74 percent capitalization rate to benefits that NEGC has used to capitalize wages and salaries (id.).

b. Company

NEGC contends that it has capitalized an appropriate amount of employee benefits costs (Company Brief at 61). The Company argues that the Attorney General incorrectly assumes that the historic capitalization ratios in Exhibit AG 1-40 were the amounts capitalized for purposes of this proceeding (id. citing Exh. AG 1-40).[70] The Company claims it did, in fact, synchronize the capitalization ratios used for its payroll, payroll tax, and benefits calculations, producing a capitalization ratio of 8.6293 percent (id. at 61-62, citing Exhs. NEGC-JMS-3,

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[70] Exhibit AG 1-40 contains the dollar amounts and capitalization percentages of salaries and benefits for 2005 through 2007 based not only payroll system source transactions, but also on all other system source transactions, such as reclassification entries and general ledger accruals and reversals.

WPs G-4.1, G-5.1, G-6.1; AG 3-7). The Company argues that the difference between the 8.74 percent reported in Exhibit AG 1-40 and the 8.6293 percent referenced above is attributable to the use of other system source transaction data as the basis for the 8.74 percent capitalization ratio (id. at 62-63, citing Exh. AG 1-46).

3. Analysis and Findings

The rate at which employee wages and benefits are capitalized will vary from year to year depending on the type and mix of capital projects that a company undertakes in any given year and the particular employees engaged in those projects. D.T.E. 03-40, at 119. Nevertheless, that same capitalization ratio should be applied to payroll expense and associated benefits in any given year.

The Department has examined the workpapers supporting the Company's revenue requirement calculations, and finds that NEGC has applied the same capitalization ratio to payroll expense, benefits, and payroll taxes (Exh. NEGC-JMS-3, WPs G-4.1, G-5.1, G-6.1). Therefore, the Department finds that no further adjustment to the Company's capitalization benefits ratio is warranted.

E. Workers' Compensation Insurance

1. Introduction

During the test year, the Company booked $18,591 in workers' compensation insurance expense (Exh. NEGC-JMS-2, Sch. G-18). The Company has proposed a total workers' compensation insurance expense of $29,175, representing an increase of $10,584 (id.).

NEGC allocates workers' compensation insurance on the basis of employees. Amounts allocated by SUG at the corporate level are initially recorded as prepayments, which are then amortized (Exh. NEGC-JMS at 19). The Company states that because the monthly entries had not been adjusted to recognize changes in allocated premiums, correcting journal entries were required, which resulted in test year expense being significantly less than normalized insurance expense (id.). The entire amount was booked to Account 925 (injuries and damages) (Exh. NEGC-JMS-2, Sch. G-18; Tr. 6, at 731).

The proposed expense level was derived by multiplying a total payroll expense of $7,557,285 by the sum of the basic premium rate of 0.1828534 per $100 in payroll and the Massachusetts special trust fund rate of 0.07137 per $100 in payroll, producing a total workers' compensation expense component of $19,212 (Exh. NEGC-JMS-3, WP G-18.2). The Company then added a retroactive premium component of $8,694, plus an allocated share of SUG's corporate workers' compensation insurance expense of $1,268, to arrive at a total workers' compensation insurance expense of $29,175 (id., WP G-18.2).

2. Positions of the Parties

The Attorney General contends that the Company failed to capitalize an appropriate amount of workers' compensation insurance expense (Attorney General Brief at 33). According to the Attorney General, the USOA-Gas Companies requires that all labor costs, including both wages and benefits, be capitalized and included in the cost of plant in service (id.). The Attorney General proposes that 8.74 percent of workers compensation insurance expense be capitalized and thus removed from cost of service (id. at 33-34, citing Exh. AG 1-40).[71] No other party addressed this issue.

3. Analysis and Findings

NEGC has booked all of its workers' compensation insurance costs to operating expenses (Exh. NEGC-JMS-2, Sch. G-18). The Department has previously recognized workers' compensation insurance as an employee benefit and, as such, has found that a portion of this expense should be capitalized. D.T.E. 05-27, at 134. Consistent with our findings on NEGC's other capitalized benefits, the Department will apply a capitalization ratio of 8.6293 percent to workers' compensation insurance expense. See Section IV.E. above. Application of an 8.6293 percent capitalization ratio to the Company's proposed workers' compensation insurance expense of $29,175 produces a capitalized amount of $2,518. Accordingly, the Company's proposed cost of service will be reduced by $2,518.

F. Bad Debt

1. Introduction

During the test year, NEGC booked $1,571,569 to uncollectible expenses (Exh. NEGC-JMS-2, Sch. G-10). The Company recovers uncollectible expense associated with (1) distribution service through base rates; and (2) supply through the CGAC.[72]

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71 As discussed above, the Attorney General contends that the Company capitalized 8.74 percent of its employee wages and salary costs (Attorney General Brief at 33, citing Exh. AG 1-40).

72 The uncollectible expense associated with supply is recovered dollar-for-dollar through the CGAC and is not at issue in this proceeding.

The Company determined the level of bad debt expense to be recovered through base rates by dividing its total net write-offs for 2005 through 2007 of $4,763,778 by its total billed revenues for that same period, including CGAC revenues, of $232,194,454, resulting in a bad debt ratio of 2.05 percent (id., WP G-10.1). The Company then multiplied the bad debt ratio of 2.05 percent by test year billed revenue of $85,210,258 to arrive at its proposed uncollectible requirement of $1,748,174 (id., WP G-10.1). Based on the ratio of base rate revenue to total revenues in the test year, the Company determined that $540,457 of uncollectible expense should be assigned to base rates and the remainder of $1,207,717 of uncollectible expense should be assigned to the GAF (id., WP G-10.1).

NEGC subsequently revised the method to calculate requested uncollectible expense to remove all revenues collected through the GAF from the calculation (RR-DPU-61-A). This revised method computed a bad debt ratio of 1.52 percent which, when applied only to the distribution revenues of $22,108,501, results in a proposed uncollectible expense of $336,049 to be included in base rates (RR-DPU-61-A).

2. Positions of the Parties

NEGC states that its calculation of uncollectible expense is consistent with the Department's historical approach (Company Brief at 65, citing RR-DPU-61-A; D.T.E. 05-27, at 175; D.T.E. 03-40, at 264; D.P.U. 95-40, at 54-55; D.P.U. 96-50, at 71). No other party commented on uncollectible expense.

3. Analysis and Findings

The Department permits companies to include for ratemaking purposes a representative level of uncollectible revenues as an expense in cost of service. D.P.U. 96-50 (Phase I) at 70-71; D.P.U. 89-114/90-331/91-80 (Phase One) at 137-140. The Department has found that the use of the most recent three years of data available is appropriate in the calculation of bad debt. D.P.U. 96-50 (Phase I) at 71. When a company is allowed dollar-for-dollar recovery of bad debt expense associated with supply through the GAF, the appropriate method to calculate uncollectible expense pertaining to distribution is to remove all revenues relating to supply from the company's bad debt calculation. See D.P.U. 07-71, at 106-109. The calculation of a company's bad debt ratio factor is derived by dividing the three-year distribution-related average net write-offs by the distribution-related billed average revenues over the same period. This bad debt ratio is then multiplied by test year distribution-related retail billed revenues, adjusted for any distribution revenue increase or decrease that was approved for recovery in the current rate case. See Id.

The method used by NEGC for calculating its uncollectible revenue adjustment is consistent with Department precedent. Id.; D.P.U. 96-50 (Phase I) at 70-71; D.P.U. 89-114/90-331/91-80 (Phase One) at 137-140. NEGC's revised bad debt expense adjustment, once adjusted for the distribution revenue increase approved for recovery in this proceeding (see RR-DPU-61-A), is in conformance with the aforementioned method. Therefore, the Department approves the application of the bad debt ratio of 1.52 percent applied to test year distribution revenue, adjusted for the base distribution revenue increase.

Accordingly, NEGC shall adjust its test year level of bad debt expense of $1,571,568 by $95,928 and further adjust the test year level by $64,142 to account for the bad debt expense on the revenue deficiency.[73]

G. Postage Expense

During the test year, NEGC booked $263,622 in postage expense (Exh. NEGC-JMS-2, Sch. G-12). The Company proposes an adjustment of $15,040 to test year postage expense to normalize costs based on postal rate increases effective as of May 12, 2008 (Exh. NEGC-JMS at 16; Exh. NEGC-JMS-2, Sch. G-12). This adjustment produces a customer billing postage amount of $278,662 (Exh. NEGC-JMS-2, Sch. G-12). The parties did not address this issue on brief.

The Department recognizes postage expense as a legitimate cost of doing business. If a postal rate increase occurs prior to the issuance of an Order, the increase is eligible for inclusion in cost of service as a known and measurable change to test year expense. D.P.U. 05-27, at 194; D.P.U. 03-40, at 174-175; Massachusetts-American Water Company, D.P.U. 88-172, at 23-24 (1989); Massachusetts Electric Company, D.P.U. 800, at 29-30 (1982). A postal rate increase became effective May 12, 2008. Therefore, the proposed increase is known and measurable. The Berkshire Gas Company, D.P.U. 90-121, at 118

73 NEGC shall use a bad debt ratio of 1.96 percent to calculate the total allowed bad debt and a ratio of 1.52 percent to calculate the bad debt allowed to be recovered through base rates. The Company shall adjust the test year level of bad debt recovered through base rates of $469,144 by a reduction of $133,095 and further adjust it by $63,074 to account for the bad debt expense on the revenue deficiency.

(1990). Accordingly, the Department accepts the Company's proposed adjustment to postage expense of $15,040.

H. Professional Fees

1. Introduction

During the test year, NEGC booked a negative $82,351 in professional fees expense (Exh. NEGC-JMS-2, Sch. G-15).[74] The Company spent $83,353 for regulatory and professional fees and $170,201 for other legal fees in the test year (Exh. DPU 1-33; RR-DPU-56-A, Sch. G-15). In addition, the Company seeks recovery of $225,837 for 50 percent of the preparation costs incurred in 2007 and 2008 of NEGC's biannual gas forecast and supply plan (Exh. DPU 1-33; RR-DPU-56-A, Sch. G-15).[75] Thus, the Company seeks to recover professional fees totaling $479,391 and a total professional fees adjustment of $561,742 (RR-DPU-56-A, Sch. G-15).

NEGC's test-year accounting method incorporates invoices for all payments made in 2007, including invoices for services provided in 2006 but not billed until 2007, and excluding invoices for services provided in 2007 but not billed until 2008 (Tr. 6, at 794-795). The Company does not formally conduct a post-litigation cost-effectiveness analysis

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74 The negative $82,351 results from the reversal of an accrual that was booked in 2006 (Tr. 6, at 783).

75 The professional fees expense includes fees paid for outside services only. During the course of the proceeding, the Company corrected the calculations in its initial filing to reflect the figures noted above (Exh. DPU 1-33; RR-DPU-56-C, WPs G-15.1 through G-15.3).

(Exh. DPU 1-40). NEGC conducts competitive bidding for any legal matter that has a known minimal cost of $50,000 or more at its outset (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that the Department should reject the Company's entire request for recovery of professional fees and other outside services, which the Attorney General calculates to be an increase of approximately $750,000 in rates above the test year amount (Attorney General Brief at 42).[76] The Attorney General argues that the Company has provided little justification for this $750,000 increase and has not exercised any cost controls to ensure that the fees are reasonable (id. citing Attorney General v. Department of Telecommunications and Energy, 438 Mass 256, 264 n.13 (2002); The Berkshire Gas Company, D.P.U. 96-67, at 6 (1996); G.L. c. 164, § 94). In fact, the Attorney General argues that the overall level of the Company's outside service expense is unreasonable (Attorney General Reply Brief at 23).

The Attorney General argues that the Company appears to be seeking double recovery from ratepayers for gas supply services because the Company pays a management fee to SUG for assistance in gas supply services and is also seeking recovery of gas supply-related expenses as part of its professional fees (Attorney General Brief at 42; Attorney General Reply Brief at 23). The Attorney General argues that it is unreasonable to pay an outside vendor to

[76] The Attorney General calculates this amount as the proposed increase for professional fees ($564,969) plus the proposed increase for rate case expense ($181,218), for a total of $747,187 (Attorney General Reply Brief at 23).

perform a task that is already being done on a day-to-day basis by SUG staff (Attorney General Reply Brief at 23). The Attorney General contends that the Department should either disallow the total requested increase or keep the expense level for outside services at test year levels (Attorney General Brief at 42).

b. Company

NEGC argues that its proposed professional fees and outside service costs for the test year are reasonable and well-supported and, therefore, should be approved (Company Brief at 73; Company Reply Brief at 12). NEGC opposes the Attorney General's recommendation that the Department disallow recovery of professional fees and outside services (Company Brief at 69). NEGC argues that the Attorney General misrepresents the amount of test-year professional fees that the Company is requesting to be included in the Company's cost of service, and then attempts to rationalize, without evidentiary support, why the amount should be removed (id. citing Attorney General Brief at 42).

The Company states that the increase of $750,000 cited by the Attorney General actually relates to multiple items in the Company's cost of service filing, not just professional fees and outside services (id.). Specifically, the Company claims that the Attorney General has included, in her figure, rate case expense amortization and SUG's management fees (id.). The Company also notes that the sum of these three components produces a combined test-year adjustment of $852,264, not $750,000 as the Attorney General calculates (id. at 69-70).

Accordingly, NEGC argues, it is unclear which test-year expenses the Attorney General is urging the Department to leave unadjusted (id. at 70).[77]

NEGC argues that the evidence demonstrates that these fees are reasonable (id.). The Company notes that the test-year expense for professional fees was a negative $82,351, owing to a large reversal of an accrual that was booked in 2006 (id. at 70-71). The Company contends that if the Department followed the Attorney General's recommendation to disallow the total requested increase or keep the expense level at test year levels, it would result in a finding that an ongoing negative level of expense is reasonable (id.). The Company argues that a significant increase to a particular test-year expense is appropriate if the test-year level of that expense is significantly understated, as is the case when the test-year expense is negative (id.).

Regarding the Company's request for expenses associated with ongoing legal and regulatory expenses, the Company states that it removed out-of-period and non-recurring items and eliminated the effect of accounting anomalies, so that the level of expense in the cost of service actually reflects those test-year costs (id. at 71-72). Thus, NEGC asserts that it properly applied the Department's standard ratemaking practice with respect to professional fees (id.).

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77 According to NEGC, the sum of the adjustments for professional services and management fees in its original filing totaled $751,532 (Company Brief at 70). The Company assumes that, because the Attorney General's brief includes a separate argument regarding rate case expense, that the Attorney General's recommendations regarding "professional services" relate only to the schedules concerning professional fees and the portion of management fees regarding gas supply support costs (id.).

With respect to biannual gas supply forecast costs, the Company states that it would be contrary to the notion of calculating a normalized annual level of cost associated with recurring activities to apply the Attorney General's recommendation (id. at 72). The Company explains that it includes in its professional fees the amount of $225,837, which is 50 percent of its biannual gas supply forecast costs, none of which were charged to expense during the test year (id.). The Company speculates that if the test year had happened to coincide with the particular biannual year in which gas supply/forecast expenses were incurred and charged to expense, the Attorney General would recommend inclusion of only 50 percent of those costs on a normalized basis (id.). Therefore, the Company argues, that is exactly what should be included when, as in this instance, the test year happens to be the biannual year in which no expenses were incurred (id.).

NEGC further contends that it is not double recovering for its gas supply services by including both the SUG management fees and the professional fees for outside consultants, as the Attorney General asserts (id.). The Company states that the Attorney General cites no evidence to support her claim that the SUG management fees for ongoing gas supply activities duplicate the payments to outside consultants for their work on the biannual gas supply forecast (id.).

3. Analysis and Findings

The Department allows a company to recover professional service or consulting fees that were booked during the test year if the fees are reasonable and if the services provide value to the company. D.T.E. 03-40, at 148, 153; D.T.E. 01-56, at 69; D.T.E. 98-51, at 47;

D.P.U. 92-210, at 51-52. The Department reviews whether the specific charges incurred were reasonable, which entails an examination of matters such as the nature of the services performed, the hourly charges, and the cost of auxiliary services (including overhead and out-of-pocket expenses such as travel). D.P.U. 89-114/90-331/91-80 (Phase One) at 44. The Department next determines whether the utility has a reasonable process in place for an on-going evaluation of the cost-effectiveness of the services provided. Id. at 44-45. Finally, the Department reviews whether the service provided was obtained through a competitive bid. For those outside services that were not competitively bid, the company should be prepared to justify why competitive bidding was not used and why its choice of service provider was reasonable and effective. D.P.U. 93-60, at 233; D.P.U. 92-250, at 128-129.

The Company claims a professional fees adjustment of $561,742. The Attorney General argues that NEGC provided little justification for the claimed adjustment. We disagree. Our review of the invoices confirms that the expenses were actually incurred and booked during the test year, and relate to professional services (Exh. DPU 1-33). For example, the invoices regarding work performed by Concentric were received and paid in 2007 and relate to Concentric's provision of services related to NEGC's regulatory requirements (Exh. DPU 1-33-A).[78] Moreover, NEGC amended its professional fees adjustment during the proceeding, removing those expenses that it realized had been improperly booked (RR-DPU-56). Included as part of the Company's revised professional fees adjustment is

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78 As noted above, the expenses regarding the biannual gas supply were not necessarily booked during the test year.

$170,201 for various legal fees charged to Account 923 (Outside Services) during the test year (Exh. DPU 1-33; RR-DPU-56-A, Sch. G-15). After reviewing the submitted invoices, the Department finds that there is evidentiary support for only $162,421 in legal fees charged to Account 923. The Company incorrectly calculated or failed to provide invoices in support of the expenses booked (Exh. DPU 1-33-C). Accordingly, the Department will disallow $7,780 in professional fees.

The professional fee invoices provided by the Company are typically broken down by the nature of services performed, the hourly charges, and the cost of auxiliary services (Exh. DPU 1-33). Our review indicates that the services are those customarily required for regulated gas utilities (id.). Moreover, we are satisfied that the hourly charges for these services and the cost of auxiliary services are reasonable and consistent with services of this nature. Thus, we find the Company's expense level to be reasonable. The Attorney General's focus on the $750,000 increase is inapposite because that figure includes rate case expense and NEGC's parent company's management fee, not just test-year professional fees (Exh. AG-FWR at 7; Tr. 9, at 1059).[79]

Nor do we find evidence that the Company's gas forecast and supply plan expenses are duplicative, noting that even the Attorney General was unsure if the services were the same (Tr. 9, at 1060-1061). NEGC pays a management fee to SUG for assistance in gas supply services provided by the Missouri Gas supply group but the Company has demonstrated that those services are not the same as those provided by the gas forecast and supply plan

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[79] The Company's management fees are addressed in Section IV.A. of this Order.

consultants (Tr. 10, at 1240-1241).[80] Moreover, the Company testified that the gas forecast and supply plan work was not something that could have been done in-house and, in fact, has never been done in-house (id. at 1254-1255). Therefore, we find that the services provided value to the Company because NEGC could not have otherwise performed its regulatory responsibilities and requirements.

Next, we consider whether NEGC has a reasonable process in place for an ongoing cost-effectiveness evaluation of the services provided. Although the Company does not perform post-litigation analyses, NEGC is aware of what the costs will be in a non-litigated matter, becomes aware if unexpected complications or issues arise that would drive up those costs, and works closely with its consultants to manage costs (Exh. DPU 1-40; Tr. 10, at 1378). While the Attorney General argues that the Company has not exercised any cost controls to ensure that its fees are reasonable, we find that the Company performed appropriate measures to control its costs. Thus, we find that there is a reasonable process in place for evaluating the services provided.

Finally, although only the biannual gas supply services were secured under a competitive bidding process, the Department recognizes that an outside firm's long-term relationship and institutional experience with a company can, in certain circumstances, satisfy a lack of competitive bidding in securing such professional services. D.T.E. 05-27, at 241; D.T.E. 03-40, at 148-149; D.T.E. 02-24/25, at 192-193; D.T.E. 01-56, at 76. In this case,

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80 In particular, the Missouri Gas supply group works on NEGC's load and sendout information, collecting and maintaining gas nominations data (Tr. 1, at 58, 142-143).

the Company demonstrated that it produced savings by relying on established relationships with consultants and not conducting a request for proposal ("RFP") process for every routine matter (RR-DPU-64; Tr. 10, at 1375-1376). Moreover, two of the consultants had been initially hired pursuant to a competitive bidding process two years earlier (RR-DPU-64). Therefore, the Department finds that the prior institutional relationships and expertise provided by NEGC's professional consultants satisfy the competitive bidding requirement in this instance. D.T.E. 05-27, at 241.

Based on the above analysis, the Department will allow $553,962 for NEGC's professional fees and outside services adjustment. Accordingly, the Company's proposed cost of service will be reduced by $7,780.

I. Excess Liability Insurance

1. Introduction

NEGC receives insurance coverage through policies acquired by its parent company, SUG (Exh. NEGC-JMS at 18).[81] During the test year, NEGC booked $180,241 in insurance expense (Exh. NEGC-JMS-2, Sch. G-18.1). The Company proposes to increase this expense by $225,993 to recognize the most recent premiums paid by NEGC, as well as to correct the expense recorded during the test year (Exhs. NEGC-JMS at 19; NEGC-JMS-2, Sch. G-18).

According to the Company, premiums are competitively bid and renegotiated annually by SUG's insurance broker (RR-DPU-16). Then, based on a series of allocation factors, the

[81] Insurance policies cover a number of areas, including automobile, crime, punitive damages, and workers compensation.

premiums are allocated to the subsidiary business units, such as NEGC (Exh. NEGC-JMS at 18; RR-DPU-17). NEGC then records the allocated amount as a prepayment on its books (Exh. NEGC-JMS at 18-19; RR-DPU-17). Monthly journal entries are made to amortize the prepayment, with an offsetting charge to insurance expense (Exh. NEGC-JMS at 19; RR-DPU-17).

During the test year, the Company determined that its monthly amortizations made during and prior to the test year had not been properly adjusted to recognize changes in allocated premiums, and thus made correcting journal entries (Exhs. NEGC-JMS at 19; AG 3-32). Consequently, the Company's test year insurance expense was significantly less than its normalized insurance expense (Exh. NEGC-JMS at 19).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that NEGC has allowed SUG to allocate a greater share of the excess liability insurance premium than appropriate (Attorney General Brief at 34). Specifically, the Attorney General asserts that the four-factor allocation formula used to apportion the excess liability premiums is unsuitable because it fails to incorporate any factor for the vast majority of its operations – the plant the Company has in service (id. at 34, citing Exh. NEGC-JMS-3, WP G-18.4 (Insurance Allocation: Four Factor Formula)). The Attorney General contends that it is reasonable to assume that insurance companies would consider property as a factor in determining the amount of insurance liability (Attorney General Reply Brief at 28). The Attorney General notes that the Company has provided a more appropriate allocation factor that includes the balance of property, plant, and equipment, as well as revenues and throughput (Attorney General Brief at 35, citing Exh. NEGC-JMS-3, WP G-18.4 (Insurance Allocation: Three Factor Formula)). She argues further that the Company has incorrectly claimed that the allocation factors are dictated by the insurance companies (Attorney General Reply Brief at 27-28, citing Company Brief at 76).

b. Company

The Company disagrees with the Attorney General's allegation that the allocation factor used for excess liability premiums is inappropriate. The Company claims that the use of the four-factor allocation formula is consistent with cost causation principles because it is based on the same determinants its insurance company uses to determine premiums (Company Brief at 76, citing RR-DPU-17). The Company further argues that the opinion of its insurance provider is more reliable than the opinion of the Attorney General in regards to what factors should be considered in determining appropriate premium levels (id.). Finally, the Company asserts that the Attorney General inappropriately assumes that NEGC has discretion in the allocation amounts that it will accept from SUG (Company Reply Brief at 15-16).

3. Analysis and Findings

Rates are designed to allow for recovery of a representative level of a company's revenues and expenses based on an historic test year adjusted for known and measurable changes. D.P.U. 02-24/25, at 161; D.P.U. 92-250, at 106. As stated above, the insurance programs and policies for NEGC are evaluated annually with the aid of an insurance broker to determine the appropriate form and price of coverage (RR-DPU-16). Accordingly, the

Department finds that the Company has taken reasonable measures to control costs. See, e.g., D.T.E. 05-27, at 134.

In determining the appropriate allocation factor, SUG is using an allocation factor consistent with that used by the insurance companies to develop the amount of the premiums they charge SUG (RR-DPU-17). Contrary to the Attorney General's arguments regarding what determinants should be considered by insurance companies when setting premiums, the record shows that the components of the four-factor allocator are what determines the premium level for excess liability insurance (id.). Thus, the Department finds that NEGC has used allocation factors that fairly represent cost causation, and we, therefore, find that the amount of premium allocated to NEGC for excess liability insurance is appropriate.

J. Injuries and Damages

1. Introduction

During the test year, the Company booked $493,716 in injury and damage claims expense (RR-DPU-56-A). NEGC states that because it experienced unusually large non-recurring claims, legal expenses, and insurance reimbursements relating to asbestos cases during 2007, it did not consider the test year expense representative of its injury and damage claims expense (Exh. NEGC-JMS at 19). Therefore, the Company proposed to reduce its test year cost of service by $340,857 to remove test year expenses related to asbestos claims (RR-DPU-56-A; RR-DPU-56-C, WPs G-19.1 through G-19.3). No other party commented on this matter on brief.

2. Analysis and Findings

The Department recognizes three classes of expense as qualified for recovery: (1) annually-recurring expenses; (2) periodically-recurring expenses; and (3) extraordinary non-recurring expenses. D.P.U. 1270/1414, at 33. Non-recurring expenses incurred in the test year are ineligible for inclusion in the cost of service unless it is demonstrated that they are so extraordinary in nature and amount as to warrant their collection by amortizing them over an appropriate time period. Id.

The Department has examined the Company's proposed adjustments, and finds that NEGC has made the appropriate accounting adjustments to eliminate these non-recurring expenses from cost of service (Exhs. AG 3-39; AG 3-40; RR-DPU-56-C, WPs G-19.1 through G-19.3). Therefore, the Department accepts the proposed adjustment.

K. Rate Case Expense

1. Introduction

In its initial filing, NEGC estimated that it would incur $1,212,251 in rate case expense (Exh. NEGC-JMS-2, Sch. G-20). During the course of the proceeding, the Company reduced the amount of its estimated rate case expense to $1,069,000, based on the Department's dismissal of the Company's revenue decoupling proposal and the need for fewer hearing days than originally anticipated (Exhs. DPU 5-3; DPU 5-6; Tr. 7, at 863-864, 868-871; Tr. 9, at 1196-1202; RR-DPU-39; RR-DPU-50; RR-56-A, Sch. G-20).[82] Having submitted its final

[82] In New England Gas Company, D.P.U. 08-35, Interlocutory Order on Scope of Proceeding and Request of the Attorney General and New England Gas Company to (continued…)

invoices, the Company now states that its total rate case expense is $1,178,282 (Exh. DPU 1-20-A Supp.).

The Company's proposed rate case expense includes: (1) legal services; (2) preparation and expert service regarding the depreciation study; (3) research, preparation, and expert service regarding the cost of capital analysis; (4) preparation and expert service regarding the embedded cost of service, marginal cost studies, and rate design; (5) preparation and expert service regarding the cost of service and revenue deficiency; and (6) other associated costs such as copying, shipping, office supplies, and transcripts (Exh. NEGC-JMS-2, Sch. G-20).

The Company issued RFPs for consultants to provide the following services: (1) cost of service witness; (2) cost of capital and capital structure study; (3) allocated cost of service and long-run marginal cost studies; (4) depreciation study; (5) combined rate design, schedule, and tariffs; and (6) regulatory legal services (Exh. DPU 1-21). NEGC received at least two proposals per RFP and chose its consultants by evaluating such factors as price, familiarity with the Company's operations, past performance with the Company, reputation, and potential to deliver services on time and within budget (Exhs. DPU 1-28; DPU 5-4; DPU 5-5; AG 9-4 (Corrected); AG 9-9; AG 9-22).

Initially, NEGC proposed to normalize its rate case expense over a five-year period, based on the average duration between the test years of its current and three prior rate cases (Exh. NEGC-JMS-2, Sch. G-20). The Company subsequently recalculated its normalization

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82 (…continued)
Bifurcate at 6 (2008), the Department found that the Company was not eligible to file a decoupling mechanism at this time.

period to be six years, based on the average duration between the filing dates, rather than test years, of its current and three prior rate cases (Exh. AG 9-29). Normalizing the rate case expense of $1,178,282 over six years produces a pro forma rate case expense of $196,380, which results in a proposed increase to test year cost of service of $181,218.

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that although NEGC has an affirmative duty to contain rate case expense, the Company does not appear to have made efforts to do so, either by using in-house staff and resources or by engaging in a meaningful competitive bidding process (Attorney General Brief at 39, citing D.T.E. 98-51, at 57; Attorney General Reply Brief at 20). The Attorney General contends that the Department should deny the Company's request to recover that portion of rate case expense which the Company did not seek to mitigate (Attorney General Brief at 40).

More specifically, the Attorney General argues that the Company has failed to show that its choice of legal services was both reasonable and cost-effective (id. at 40-41, citing D.T.E. 03-40, at 153; Attorney General Reply Brief at 20). The Attorney General claims that the Company chose a legal services consultant that did not offer the lowest bid, without knowing the estimated number of hours that the firm expected to bill and without attempting to negotiate any of the legal fees (Attorney General Brief at 40-41). The Attorney General further claims that the Company did not conduct a meaningful economic analysis to support its selection, nor did it show that its economic analysis was conducted in accordance with

Department precedent (id. at 41; Attorney General Reply Brief at 20, citing D.T.E. 03-40, at 153). Moreover, the Attorney General contends that while the Company described the evaluation process regarding the competitive bids for legal services, it failed to produce any contemporaneous documentation to show that its choice was both reasonable and cost-effective (Attorney General Reply Brief at 20-21). Thus, the Attorney General argues, the Department should deny the Company's request to recover any rate case expense for legal services above the average of the four bids provided in response to the RFP (Attorney General Brief at 41).

In addition, the Attorney General argues that NEGC may be double-charging customers for a depreciation study that was used in both the Company's 2007 rate case and the current rate case (Attorney General Brief at 41; Attorney General Reply Brief at 21-22). The Attorney General contends that, although NEGC has excluded the cost of the depreciation study itself, the Company is not entitled to recover for any of the costs associated with litigating the issue because depreciation was an issue in the last rate case, and any adjustments to depreciation expense were included as part of the settlement in that case (Attorney General Reply Brief at 22). Reintroducing the issue in this case, the Attorney General argues, results in double charging the Company's customers (id. citing The Berkshire Gas Company, D.T.E. 04-47, at 29-30 (2004)).

Finally, the Attorney General asserts that the Company seeks to include in rate case expense the cost of embedded and marginal cost of service studies that were not used in the rate design and revenue allocation portions of the current rate case (Attorney General Brief at 41). According to the Attorney General, if the Department did not require these studies to be filed, then the Department should exclude the preparation cost of $276,000 from rate case expense (id. at 42). If the Department did require the studies, then the Company should be allowed to recover for it only in the range of $40,000 to $90,000, not the proposed amount of $276,000 (id. citing Tr. 9, at 1086).[83]

b. Local 431

Local 431 contends that NEGC's rate case expense adjustment is exorbitant, amounting to more than 20 percent of the Company's requested rate increase of $5.6 million and, therefore, should be reduced (Local 431 Brief at 15-16 & n.18). With respect to the normalization period, Local 431 argues that, although the average number of years between the Company's prior rate case filings is five years, the two-year duration between this rate case filing and the last rate case filing is anomalous and therefore unrepresentative of the average duration between rate cases (id. at 16). Thus, Local 431 recommends that the normalization period for rate case expense be seven years based on removal of the anomalous two-year period (id.).

c. Company

NEGC argues that, contrary to the Attorney General's contention, the record demonstrates that the Company adequately contained rate case expense in several respects (Company Brief at 78). First, the Company states that because it had limited in-house

[83] The Attorney General bases her proposed recovery on the amount that her witness testified he would have charged for such studies (Tr. 9, at 1086).

resources with sufficient rate case expertise,[84] it strictly followed the Department's precedent regarding rate case expenses by using a competitive solicitation process for 100 percent of the total anticipated expense (id. at 78-79, citing D.T.E. 05-27, at 158-159; D.T.E. 03-40, at 148, 153; D.T.E. 02-24/25, at 192; Company Reply Brief at 10-11). In addition, the Company contends that it selected experienced consultants who were familiar with both the Company's operations and Department precedent (Company Brief at 78). The Company further states that NEGC's manager of regulatory affairs and chief operating officer evaluated the proposals separately, then met to reach a consensus on which vendor to use (id. at 79). According to the Company, these two people evaluated each proposal using the same criteria: proposed price; the vendor's familiarity with NEGC (including the service territory, as well as Company personnel and procedures); the vendor's past performance (if any) with the Company; the vendor's reputation; and the vendor's potential to deliver the service on time and within the proposed budget (id.). Moreover, according to NEGC, and contrary to the Attorney General's assertion, the Department does not require contemporaneous documentation of the internal review process for rate case consultants (Company Reply Brief at 11).

The Company states that it chose the lowest bidder for the cost of capital study and the internal cost of service (revenue requirement) witness (Company Brief at 79). The Company further states that it chose the second lowest bidder for the allocated cost of service and marginal cost studies, as well as for rate design, but that the difference between these bids was

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84 The Company notes that it reduced its FTE employees following the 2006 Rhode Island asset sale (Company Reply Brief at 10-11).

small and the winning bidder was more familiar with NEGC and had a local presence, thereby minimizing travel expenses (id.). For the depreciation RFP, the Company picked the highest bidder, but states that the difference in bids was only $4,000, and the winning bidder was much more familiar with the Company and had, in fact, prepared the depreciation study for the Company's last rate case (id. at 79-80).

The Company notes that, in analyzing the results of the legal services RFP, it focused not on the proposed total costs but on the proposed hourly rates (id. at 80). The Company states that it did so because the number of hours required is beyond the control of the Company or its legal services provider, and the total cost is dependent on the contentiousness of the proceeding, which is impossible to know prior to filing the case (id.). The Company explains that it disregarded those legal service bidders who provided a total cost estimate because: (1) the actual number of hours spent on the filing would be the same for every legal services provider in the end; and (2) some of the estimates appeared unrealistically low given the nature of the Company's filing (id.).

The Company maintains that the winning legal services bidder was the only one to offer a graduated discount that decreased the hourly rate as the number of hours increased (id.). The Company argues that, even at the lowest level discount, the average hourly rates of the winning bidder were in the same range as all other respondents, but that the rate would decline if the number of hours exceeded a threshold (id.). According to the Company, no other bidder offered to discount the hourly rate or provided a blended or an average rate (id.). In addition, NEGC states that the winning firm was most familiar with the Company, which the Company believed might reduce the number of hours necessary to prepare and defend the filing (id. at 80-81). In sum, the Company argues that the record shows that NEGC selected a legal services provider that would cost no more than any other bidder and, perhaps, would cost even less given its knowledge of NEGC (id. at 81).

NEGC next asserts that the Attorney General's allegations of excessive charges relating to the Company's depreciation study and marginal cost study are factually incorrect and/or unsupported (id. at 81-82). First, the Company argues that it is not double charging for the 2006 depreciation study because it is including only those expenses related to litigating the depreciation issue, not the cost of the study itself (id. at 81). Second, the Company argues that it did not fail to contain rate case expenses related to its marginal cost study (id. at 81-82). The Company states that it properly included the costs to complete a marginal cost study because the Department has long required gas companies to file marginal cost studies with requests for base rate relief (id. at 82; Company Reply Brief at 12). NEGC also states that its marginal cost study costs are a fraction of the $276,000 figure cited by the Attorney General (Company Brief at 82). Therefore, the Company contends that the Department should reject what it characterizes as the Attorney General's unsupported and inaccurate allegations regarding the cost of NEGC's depreciation study and marginal cost study (id.).

NEGC also asserts that the Department should reject Local 431's recommendation of a seven-year normalization period for rate case expense (id. at 78 n.20). According to the Company, ignoring the time period between the current rate case filing and the prior rate case filing would be inconsistent with Department precedent (id.).

3. Analysis and Findings

The Department allows recovery for rate case expense based on two important considerations. First, the Department permits recovery of rate case expense that has been actually incurred and, thus, is considered known and measurable. D.P.U. 07-71, at 99; D.T.E. 05-27, at 157; D.T.E. 98-51, at 61-62.[85] Second, such expenses must be reasonable, appropriate, and prudently incurred. D.T.E. 05-27, at 160-161; D.T.E. 98-51, at 58; D.P.U. 95-118, at 115-119; Dedham Water Company, D.P.U. 84-32, at 14 (1984).

The overall level of rate case expense among utilities has been, and remains, a matter of concern for the Department. D.P.U. 07-71, at 99; D.T.E. 03-40, at 147; D.T.E. 02-24/25, at 192; D.P.U. 93-60, at 145. Rate case expense, like any other expenditure, is an area where companies must seek to contain costs.[86] D.P.U. 07-71, at 99; D.T.E. 03-40, at 147-148; D.T.E. 02-24/25, at 192; D.P.U. 96-50 (Phase I) at 79.

The Department has consistently emphasized the importance of competitive bidding for outside services in a company's overall strategy to contain rate case expense. See, e.g., D.T.E. 05-27, at 158-159; D.T.E. 03-40, at 148; D.T.E. 02-24/25, at 192. If a company elects to secure outside services for rate case expense, it must engage in a competitive bidding

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85 While companies may seek recovery of rate case expense incurred on a fixed-fee basis for work performed after the close of the evidentiary record (e.g., for completion of necessary compliance filings), the reasonableness of the fixed fees must be supported by sufficient evidence. D.T.E. 02-24/25, at 196.

86 The Department has also found that rate case expenses will not be allowed in cost of service where such expenses are disproportionate to the relief being sought. See Barnstable Water Company, D.P.U. 93-223-B at 16 (1993).

process for these services. D.P.U. 07-71, at 99-100, 101; D.T.E. 03-40, at 153. If a company decides to forgo the competitive bidding process, the company must provide an adequate justification for its decision to do so. D.T.E. 01-56, at 76; D.T.E. 98-51, at 59-60; D.P.U. 96-50 (Phase I) at 79.

The Attorney General asserts that NEGC did not engage in a meaningful competitive bidding process because it failed to show that its choice of legal services provider was both reasonable and cost-effective (Attorney General Brief at 40-41; Attorney General Reply Brief at 20-21). More specifically, the Attorney General notes that the Company did not provide any contemporaneous documentation of its evaluation process and did not choose the lowest bidder for legal services (Attorney General Brief at 40-41). Thus, the Attorney General says that the Department should deny NEGC's request to recover any rate case expense for outside legal services above the average of the four bids provided in response to the RFP (id. at 41). We disagree. The Company followed Department precedent by employing a competitive bidding process for each of its rate case expense outside service providers. While the Department requires companies to maintain contemporaneous documentation on cost-benefit analyses for capital projects, this requirement does not necessarily apply to the solicitation process for rate case expense. See D.T.E. 03-40, at 83-84.[87] Nevertheless, the Company has

[87] This is because prudency of rate case expense is evaluated at a time proximate to the solicitation process. The decision-making process for capital projects, however, may be more prone to skepticism and impeachment because the projects at issue may be completed years before their prudency is evaluated as part of a rate case. D.T.E. 05-27, at 94 n.70.

the burden to demonstrate that its selection of service providers was prudent and appropriate. This burden is especially great where the Company did not choose the lowest bidder, and the best evidence to aid the Company in satisfying its burden is contemporaneous documentation of its well-analyzed decision making. See Id. In this case, the Company demonstrated that it conducted a thorough evaluation process and selected experienced consultants who were familiar with both NEGC's operations and Department precedent (Exhs. DPU 1-28; DPU 5-4; DPU 5-5; AG 9-9). On balance, therefore, we find that the Company made a sufficient showing that its selection of service providers was prudent and appropriate to meet its burden. We note, however, that it would benefit the Company to maintain contemporaneous documentation of its decision making to satisfy this burden in the future.

Furthermore, obtaining competitive bids does not mean that a company must then necessarily retain the services of the lowest bidder; rather, the bidding and qualification process merely provides a benchmark for reasonableness of the cost of the services sought. D.P.U. 07-71, at 101; D.T.E. 03-40, at 152. In each instance where NEGC did not retain the lowest bidder, the Company demonstrated that it carefully evaluated its options, picking the provider that it believed would provide the best and most cost-effective services (Exhs. DPU 5-5, at 3; AG 9-22; Tr. 9, at 1189-1191, 1193-1194). For most of the RFPs, the bids received were relatively close in terms of price. Regarding the legal services bids, the Company rejected fixed fee proposals in favor of a bid based on hourly rates with a graduated billing structure. Accordingly, the Company sufficiently demonstrated the reasonableness of its selections of legal services consultants.

The Attorney General also asserts that NEGC did not make efforts to contain costs by using in-house staff where possible (Attorney General Brief at 40; Attorney General Reply Brief at 20). We recognize that the Company may not have had the appropriate in-house resources with which to conduct the rate case (Exh. AG 9-3; Tr. 10, at 1254-1255, 1368-1369). Nevertheless, we find that NEGC made other efforts to contain costs by using a competitive bidding process for 100 percent of the total anticipated expenses, evaluating each proposal pursuant to the same criteria, and selecting experienced consultants who were familiar with both the Company's operations and Department precedent (Company Brief at 78-79; Company Reply Brief at 10-11).

The Attorney General further contends that the Company may be double charging customers for the depreciation study costs because there was no need to litigate the depreciation issues in this rate case (Attorney General Brief at 41; Attorney General Reply Brief at 21-22). We disagree. The Company is seeking to recover as part of its rate case expenses only those costs related to litigation of the depreciation issues in this proceeding and is not seeking to recover the actual costs of the depreciation study (Exh. AG 9-15-E; Tr. 9, at 1115-1116). The submission of the depreciation study in the last rate case does not mean that the depreciation issues were satisfactorily addressed for our purposes here (Tr. 9, at 1135-37; see also D.P.U. 07-46). This is particularly true because the last rate case concluded with a settlement which, in relevant part, specifies that NEGC would maintain its then-current depreciation rates. D.P.U. 07-46, Settlement Agreement at Article 2, § 2.8. Moreover, we note that outcomes reached in settlement discussions carry no precedential weight and the Department's approval of an offer of settlement carries no precedential value. D.P.U./D.T.E. 97-95, at 25; Dover Water Company, D.P.U. 90-86, at 3-5 (1990). Cf. Fitchburg Gas and Electric Light Company, D.T.E. 99-66-A at 5-6 (2001) (Department is not precluded from scrutinizing independent facts arising out of settlement discussions or offers of settlement).

Finally, the Attorney General argues that the Company improperly includes the cost of the embedded and marginal cost of service studies in rate case expense (Attorney General Brief at 41-42; Attorney General Reply Brief at 22). We find that where the Department requires these studies to be filed as part of the rate case, the Company properly included its costs in rate case expense (Tr. 9, at 1057, 1140-1141; D.P.U. 84-145-A at 150; Colonial Gas Company, D.P.U. 84-94, at 70-73 (1984)).

Companies must provide all invoices for outside rate case services that detail the number of hours billed, the billing rate, and the specific nature of the services performed. D.P.U. 07-71, at 102; D.T.E. 03-40, at 157; D.T.E. 02-24/25, at 193-194; D.P.U. 96-50 (Phase I) at 79. Failure to provide this information will result in the Department's disallowance of the corresponding portion of rate case expense. D.P.U. 07-71, at 102; D.T.E. 02-24/25, at 193-194; D.P.U. 96-50 (Phase I) at 79.

In the present case, the Company's invoices were properly itemized for allowable expenses, with a few exceptions discussed below. The Department's longstanding precedent allows only known and measurable changes to test-year expenses to be included as adjustments to cost of service. D.T.E. 03-40, at 161; D.T.E. 02-24/25, at 195; D.T.E. 01-56, at 75;

D.T.E. 98-51, at 61-62. Proposed adjustments based on projections or estimates are not known and measurable, and recovery of those expenses is not allowed. D.T.E. 03-40, at 161-162; D.T.E. 02-24/25, at 196; D.T.E. 01-56, at 75. The Department has stated that we would not preclude the recovery of fixed fees in certain cases such as for completion of compliance filing work in a rate case, but the reasonableness of the fixed fees must be supported by sufficient evidence. D.P.U. 07-71, at 102-103; D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. Thus, documented and itemized proof is a prerequisite to recovery. D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196.

NEGC has proposed to include an estimated $49,784 in rate case expense for work that has yet to be performed but is not otherwise identified (Exh. DPU 1-20-A Supp.). The Company does not explain what these estimates are for and does not present any evidence to support their reasonableness, such as the number of hours needed to complete the rate case or the other factors which the parties considered when arriving at the negotiated fee (id.). As NEGC has not demonstrated these estimates are reasonable, the Department denies recovery of them as insufficiently supported or justified.

In addition, we disallow $1,626 in expenses related to work on the Company's ESM filing, as that issue is addressed in a separate docket (Exh. DPU 1-20-B Supp.; see D.P.U. 08-64). Therefore, recovery of these items as rate case expense cannot be allowed, and the Department will reduce the rate case expense accordingly. As a result of the foregoing analysis, the Department finds that the Company's proposed rate case expense shall be reduced by a total of $51,410, bringing the total to $1,126,872.

Local 431 argues that NEGC's rate case expense is high compared to the total relief sought. While the Department is concerned about increases in rate case expense, we do not view NEGC's rate case expense as so disproportionate as to require correction in this case. The correlation between total rate case expense and the amount of relief sought is not necessarily linear. For example, the preparation and presentation of a cost-of-equity analysis would, in all likelihood, be the same for a company with 50,000 customers as for one with 500,000 customers. Similarly, a great deal of preparation work must be done in a rate case regardless of the number of hearing days or the issues that arise. In future rate cases, the Department will continue to scrutinize the overall level of rate case expense and may require shareholders to shoulder a portion of the expense.

The Department's practice is to normalize rate case expenses so that a representative annual amount is included in the cost of service. D.P.U. 07-71, at 103; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163; D.P.U. 1490, at 33-34. Normalization is not intended to ensure dollar-for-dollar recovery of a particular expense; rather, it is intended to include a representative annual level of rate case expense in cost of service. D.P.U. 07-71, at 103; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163-164; Nantucket Electric Company, D.P.U. 91-106/91-138, at 20-21 (1991).

The Department determines the appropriate normalization period for recovery of rate case expense by taking the average of the intervals between the filing dates of a company's last four rate cases, including the present case, rounded to the nearest whole number. D.P.U. 07-71, at 103; D.T.E. 05-27, at 163 n.105; D.T.E. 03-40, at 164 n.77; D.P.U. 1490, at 33-34. If the resulting normalization period is deemed unreasonable or if the company has an inadequate rate case filing history, the Department will determine the appropriate normalization period based on the particular facts of the case. D.P.U. 07-71, at 103-104; South Egremont Water Company, D.P.U. 86-149, at 2-3 (1986).

In this case, NEGC seeks a normalization period of six years (Exh. AG 9-29). Local 431 argues that the normalization period should be seven years because the two-year duration between this rate case filing and the last rate case filing is anomalous (Local 431 Brief at 16). The period between rate cases will vary for many reasons, and the Department uses the last four rate cases as a means to account for varied periods. As such, in this instance, we do not find it appropriate to exclude the two-year period between the Company's last two rate cases as we find the ultimate result of the formula to be representative. NEGC has calculated its proposed six-year normalization period consistent with Department precedent. Moreover, based on the rate case filing history of the Company, the Department finds that the six-year normalization period is reasonable and does not require further adjustment.

Based on the findings above, the Department concludes that the Company may recover rate case expense in the amount of $1,126,872, with a normalization period of six years, for a normalized rate case expense of $187,812 ($1,126,872 divided by six years). Subtracting $61,232 in test-year rate case amortization expense from $187,812 produces a total adjustment to test-year expense of $126,580. Accordingly, the Company's proposed cost of service is increased by $9,646.

L. Gain on Sale of Property

1. Introduction

In 2003, NEGC sold the building and land located at 155-157 North Main Street, Fall River, Massachusetts, that was formerly used as its administrative headquarters (Exhs. NEGC-JMS at 21; DPU 1-46). The property was originally purchased in 1912 at a cost of $27,994, and a $1,000 improvement was made to the land in 1966 (Exh. DPU 1-47; RR-DPU-38). Thus, the original book value of the property was $28,994 (Exh. NEGC-JMS-3, WP G-24.2). The 2003 sale price was $502,100, of which $170,714 was attributable to the land, and the remaining $331,386 was attributable to the building (id., WP G-24.2; Exh. DPU 1-46). The difference between the $170,714 sale price for the land and the $28,994 original value is $141,720 (Exh. NEGC-JMS-3, WP G-24.2). Thus, the Company recorded $141,720 as the gain on the sale of land (Exhs. NEGC-JMS at 21; NEGC-JMS-2, Sch. G-24). The Company states that the original cost of the building and the proceeds relating to the building were recorded to the appropriate accumulated depreciation account at the time of the sale (Exhs. NEGC-JMS at 21; DPU 2-1). The net gain on sale relating to the land was recorded as income (Exh. NEGC-JMS at 21).

NEGC proposes to amortize the gain on the land sale over a ten-year period for an adjustment of negative $14,172 (Exh. NEGC-JMS-2, Sch. G-24). The Company states that it proposed a ten-year amortization period, rather than a three- or five-year period, because the property was purchased in 1912 and the gain occurred over 90 years, during which time the property was used and useful in providing utility service to multiple generations of ratepayers

(Exh. DPU 1-47). Thus, the Company states that it sought to enable both current and future ratepayers to realize the benefit (id.).[88] Therefore, NEGC proposes to reduce its test year cost of service by $14,172 (Exh. NEGC-JMS-2, Sch. G-24).

Accordingly, NEGC states that it has properly recognized the gain on the sale of its former headquarters by reducing the Company's test-year cost of service by 1/10th of the Company's gain (Company Brief at 85). No other party addresses this issue on brief.

2. Analysis and Findings

The Department's long-standing policy with respect to gains on the sale of utility property is to require the return to ratepayers of the entire gain associated with the sale, if those assets were recorded above-the-line and supported by ratepayers. D.P.U. 96-50 (Phase I) at 111; Barnstable Water Company, D.P.U. 93-223-B at 12-13 (1994); Commonwealth Electric Company, D.P.U. 88-135/151, at 92 (1989). Therefore, if such property is sold by the utility, it is necessary to include an adjustment that recognizes the appreciation on assets that ratepayers have supported in rates through a return of and on the investment. D.P.U. 88-135/151, at 91.

The Department has reviewed the records concerning the gain on the sale of property and finds that NEGC properly booked the gain attributable to the building on the land against accumulated depreciation. The starting point for calculating the gain on the sale of property is

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88 Alternatively, at a minimum, the Company would argue for a six-year amortization period "simply because, based on the Department's precedent and calculation of rate-case expenses," a six-year period signifies that NEGC will not file another rate case for six years (Tr. 7, at 862).

generally the purchase price, unless sales expenses are incurred, in which case the purchase price is reduced by sales expenses in computing the amount realized from the sale. D.T.E. 05-27, at 147-148; D.P.U. 95-118, at 142. The settlement statement for the property specifies a total sales price of $502,100 (Exh. DPU 1-46). Of that amount, $170,714 was attributable to the land (Exhs. NEGC-JMS-3, WP G-24.2; DPU 1-46). Thus, where the original value of the land was $28,994, the gain on the sale of the land was $141,720 (Exh. NEGC-JMS-3, WP G-24.2). The Department finds that the Company has appropriately calculated the gain associated with this transaction and that its computations are consistent with the general approach used by the Department. D.P.U. 88-135/151, at 90-94. Accordingly, the Department finds that the total gain on the sale of land was $141,720.

The Company proposes a ten-year amortization period for the gain on sale of land. In D.P.U. 05-27, at 151-152, the Department approved a ten-year amortization period as appropriate because it was consistent with the ten-year term of its performance-based rate ("PBR") plan approved in the same Order. Accord D.P.U. 03-40, at 182. In that case, because the company was operating under a PBR plan, it was unlikely to submit a rate case for at least ten years. D.P.U. 05-27, at 151-152. In this case, however, NEGC has not filed a PBR and, thus, the date of the Company's next rate case cannot be determined with certainty. Therefore, the Department will determine an amortization period based on the facts of this particular case. The Company has failed to demonstrate that a ten-year normalization period is reasonable. Consistent with the Department's decision to normalize the Company's rate case expense over a period of six years (see Section IV.K., above), we find that the appropriate normalization period for the gain on the sale of the property is six years. This amortization period, applied to the $141,720 gain on the sale of the North Main Street property, produces an annual amortization of $23,620. Accordingly, the Company's proposed cost of service will be reduced by $9,448.

M. Depreciation Expense

1. Introduction

During the test year, NEGC booked $3,231,280 in depreciation expense (Exh. NEGC-JMS-2, Sch. G-1, line 31). NEGC proposed to increase its test year depreciation expense by $375,035 to $3,606,315 (id., Sch. G-1, line 31). The adjustment was computed by applying account-specific accrual rates to the test year-end depreciable plant (id., Sch. G-27). In its previous rate case, D.T.E. 07-46, the Company commissioned a depreciation study, which it also presents in the instant case to support its proposed depreciation adjustment (Exh. NEGC-PMN at 1-2). The composite accrual rates recommended by the study are 3.68 percent and 2.98 percent for the Fall River and North Attleboro service areas, respectively (id. at 13). These accrual rates represent an increase from the current rates of 3.50 percent for the Fall River service area and 2.61 percent for the North Attleboro service area (id. at 4, 13).

The study uses the remaining life method, which has long been accepted by the Department (id. at 12). The Company calculated the depreciation accrual rates by dividing the sum of net plant in service minus net salvage cost by the average remaining life (id. at 3, 12). NEGC developed average remaining life estimates based on existing records of plant additions and retirements for the plant in service as of December 31, 2005 (Exh. NEGC-PMN-2, at 10). Because the information available was incomplete, the Company relied on a simulated plant record balances ("SPR-BAL") analysis, an iterative analysis of the available records to develop a mortality dispersion table (id., at 19). These tables are then compared to a well-established set of mortality curves known as Iowa Curves[89] to produce average remaining life for each group of 28 groups of plant (id., at 12).

The depreciation study also analyzed the gross salvage and removal costs of retirements from 1995 to 2005 to develop net salvage values for each group (id., at 20). The weighted averages of the depreciation accrual rates computed for each of the plan accounts is then calculated to determine the appropriate depreciation accrual rate for the overall service area (id., Schs. A, B, C).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that flaws in the development of the proposed accrual rates limit the usefulness and applicability of the Company's depreciation study (Attorney General Brief at 29). Specifically, the Attorney General alleges that the study is based on deficient data and that, therefore, the study relies on an SPR-BAL approach used only when complete actuarial data is not available (id.). The Attorney General also points to the lack of

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[89] Iowa curves are frequency distribution curves initially developed in the 1930s at Iowa State University, and are widely accepted in determining average life frequencies for utility plant. See D.T.E. 05-27, at 242 n.142.

data on retirements and material type for distribution mains (id. citing Exh. NEGC-PMN-2, at 27; Tr. 4, at 477-479).

The Attorney General also asserts that the study ignores the results of the analysis in its recommendations (id.; Attorney General Reply Brief at 25). In support of her assertion, the Attorney General notes two examples. First, she maintains that the statistical analysis for Account 367 (mains) in the Fall River service area suggest an average service life ("ASL") of 100 years; despite this, the Company selected a 65-year curve (Attorney General Brief at 29-30, citing Exh. NEGC-PMN-2, at 27; Tr. 4, at 469-472). Second, she contends that the statistical analysis for Account 380 (services) in the Fall River service area suggests an ASL of 61 years; the Company, however, proposed the use of a 50-year ASL (id. at 30, citing Tr. 4, at 461-462).

The Attorney General claims that NEGC improperly attempts to shift the burden of proof to her by claiming that her witness failed to perform an independent depreciation study (Attorney General Reply Brief at 24). Nevertheless, the Attorney General notes that her own witness was unable to determine how the Company developed selected ASLs (id. at 24-25, citing Tr. 9, at 1129-1130). As such, the Attorney General argues that the Department should reject the depreciation study (id. at 24).

In addition to her concerns over the proposed ASLs, the Attorney General finds fault with the net salvage values used in calculating the depreciation accrual rates (Attorney General Brief at 30-31). The Attorney General asserts that there are no data to justify the changes recommended in the study (id. citing Tr. 4, at 475).

Finally, the Attorney General suggests that, as the Company has proposed combining the rates of the Fall River and North Attleboro service areas, NEGC should not continue to use separate depreciation rates for the two separate service areas (id. at 31). Therefore, she recommends using the Fall River service area depreciation accrual rate for all of NEGC's plant (id.).

b. Company

The Company disagrees with the Attorney General's assessment of the study's limitations due to the deficiencies in the raw data (Company Brief at 89). Responding to the example that the Attorney General uses to illustrate her case (i.e., lack of data on retirements by material type for Account 367), NEGC maintains that there is no accounting or regulatory requirement that a gas company track and record retirements of mains by material type (id. at 90). Furthermore, the Company contends that it is a well-established practice of the gas industry and the Department to develop single composite accrual rates for the entire mains account (id.).

The Company counters the Attorney General's charge that its ASL recommendations ignore the results of the statistical analyses, arguing that professional judgement is appropriately involved in selecting the most appropriate Iowa curve and ASL for these assets (id. at 91). The Company further argues that the record demonstrates that it performed an in-depth analysis in arriving at the recommended ASL estimates (id. at 90). The Company dismisses the service lives recommended by the Attorney General as the results of a flawed misreading of the SPR-BAL analysis and the output of the Iowa curve analysis (id. at 91).

NEGC asserts that the Attorney General has not provided a comprehensive analysis to support her recommendations (id. at 91-92).

The Company also disputes the Attorney General's charge that there are no data to support the proposed changes to net salvage values and asserts that it has shown that NEGC's historical recorded gross salvage and removal costs for the period 1995 to 2005 were collected and analyzed (id. at 92, citing Exh. NEGC-PMN-2, at 20). In addition, NEGC asserts that the Attorney General fails to acknowledge the cost of removal rate calculations performed (id. citing Exh. NEGC-PMN-2, App. F).

Finally, NEGC does not oppose the Attorney General's recommendation to use the Fall River service area depreciation accrual rates for the Company's entire service territory (id. at 93). The Company, however, maintains that the combined depreciation accrual rates should be based on the results of its depreciation study (id.).

3. Analysis and Findings

a. Introduction

Depreciation expense allows a company to recover its capital investments in a timely and equitable fashion over the service lives of the investments. D.T.E. 98-51, at 75; D.P.U. 96-50 (Phase I) at 104; D.P.U. 84-135, at 23; Boston Edison Company, D.P.U. 1350, at 97 (1983). Depreciation studies rely not only on statistical analysis but also on the judgment and expertise of the preparer. The Department has held that when a witness reaches a conclusion about a depreciation study which is at variance with that witness's engineering and statistical analyses, the Department will not accept such a conclusion absent sufficient justification for such a departure. D.P.U. 92-250, at 64; D.P.U. 89-114/90-331/91-80 (Phase One) at 54-55; D.P.U. 88-135/151, at 37; D.T.E. 01-56, at 93. It is also necessary to go beyond the numbers presented in a depreciation study and consider the underlying physical assets. D.P.U. 92-250, at 64; The Berkshire Gas Company, D.P.U. 905, at 13-15 (1982); Massachusetts Electric Company, D.P.U. 200, at 21 (1980).

b. Application of 2005 Study

The purpose of a depreciation study is to develop accrual rates that are then applied to plant balances. It is not inconsistent to apply the accrual rates developed from a plant balance as of a specific date to those plant balances in service on a different date, provided there are no significant changes in plant composition in the intervening period. D.P.U. 92-250, at 70. The Department finds the changes in the composition of NEGC's plant between December 31, 2005, and December 31, 2007, do not materially affect the validity of the depreciation study's accrual rates. The remaining life method is designed to allow periodic rate adjustments that, over the life of the property, ensure that the entire cost of the investment is collected. Maintaining depreciation rates approved in 1991 and 1996 would fail to recognize previous period under-accruals or over-accruals. Thus, we find that it is appropriate to apply the results of this depreciation study with appropriate revisions to test-year end plant.

c. Deficiency of Data

A company may not have sufficient retirement data for certain plant accounts to perform a statistically-reliable analysis of service lives, particularly in the case of smaller companies with long-lived plant. Moreover, accounting records for mass plant investment tend not to include information on the ages of the various plant retirements. These conditions preclude the use of an actuarial method to determine accrual rates. Because plant and equipment exhibit a regular pattern from year to year, SPR-BAL analyses are often used to determine the appropriate accrual rate for mass plant investments. See, e.g., D.T.E. 02-24/25, at 126. The Department has examined the basis for the SPR-BAL analyses used here and finds them to be appropriate (see Exhs. NEGC-PMN-2 App. B.2, C.2; NEGC-PMN-3; see also Tr. 4, at 456-474, 476-482). Therefore, the Department finds that the Company's application of SPR-BAL analysis addresses any shortcomings of the data.

d. Service Life Recommendations

The Attorney General argues that, in calculating the depreciation accrual rates, NEGC uses ASL estimates that are inconsistent with the statistical results of the SPR-BAL analysis (Attorney General Brief at 29-30). Two examples were cited in support of this charge: (1) Fall River mains (Account 367) and (2) Fall River services (Account 380) (id. at 29-30). In each example, the value that the Attorney General believes to be the result of the statistical analysis is simply the average taken of the entire range of 27 Iowa Curves (Exh. DPU-AG 1-5). As the curves represent very different shapes of various heights and skewness, only a few will closely approximate the service life of the plant account being analyzed (Tr. 4, at 458-460). The statistical tests incorporated with the study (i.e., conformance index, retirement index and cycle index) are used to identify the appropriate curves (Exh. NEGC-PMN-2, at 19-20; Tr. 4, at 462-463, 503). The SPR-BAL analysis provides valuable insight about the retirement history and what it would likely be in the future if the Company's experience were to remain constant for the remaining life of the surviving plant (Exh. NEGC-PMN, at 9, citing New York Department of Public Service, Computer Supported Property Mortality Studies at I.1 (1971)). It does not, however, reflect engineering opinions or Company policy (id.). The Company must, therefore, apply the SPR-BAL analysis with experience and judgment in determining the appropriate ASL of plant and equipment (id. at 9-11, citing NARUC MANUAL OF PUBLIC UTILITY DEPRECIATION PRACTICES at 126). The Department finds that NEGC has demonstrated sufficient justification for all variances from statistical analyses in determining the ASL used in calculating the depreciation accrual rates. Accordingly, the Company's proposed depreciation accrual rates are approved.

e. Net Salvage Costs

The Attorney General argues that NEGC fails to provide data supporting the changes that were made to the net salvage values used in previous rate cases. The Company counters that retirement data for the period 1995 to 2005 was analyzed in developing the salvage rates (Company Brief at 92, citing Exh. NEGC-PMN-2, at 20). Based on our review of the data and supporting calculations, the Department finds the net salvage cost values used in calculating the depreciation accrual rates to be a fair and accurate representation of the gross cost of removal and gross salvage values that NEGC experiences in the retirement of its plant and equipment (see Exh. NEGC-PMN-2, Schs. A, B, Apps. D, E). As such, the proposed net salvage values are allowed.

f. Uniform Depreciation Rate

The Attorney General recommends the application of the depreciation accrual rate for the Fall River service area to the whole of NEGC's depreciable plant because the Company has proposed consolidating rates (Attorney General Brief at 31). The Company does not object to such proposal (Company Brief at 93). The Department disagrees. The depreciation rate was developed based on the plant and equipment in the Fall River service area and does not reflect the plant and equipment in the North Attleboro service area. Thus, it would be an inaccurate representation, overstating the true depreciation expense. The Department finds that the separate depreciation rates as filed by the Company are accurate and the depreciation expense is correctly calculated based on the results. Given the fact that the Department is approving consolidation of rates for the Fall River and North Attleboro service areas (see Section VII.D. below), the Company is instructed that in any subsequent depreciation study filed with the Department, it is to combine the assets of the Fall River Service area and the North Attleboro service area prior to analysis and provide one depreciation rate for each category of plant, encompassing the entirety of the distribution system.

g. Conclusion

Based on the above analysis, the Department has accepted the results of the Company's depreciation study. The depreciation accrual rates are to be used by NEGC in determining its depreciation expense going forward until such time as it is superceded by a new updated and approved study.

N. Property Taxes

1. Introduction

During the test year, NEGC booked $859,464 to property tax expense (Exh. NEGC-JMS-2, Sch. G-28). The Company has proposed an adjustment to property tax in the amount of $67,688 (id., Sch. G-28). Subsequently, the Company submitted a revised estimate of their property tax in the amount of $65,362 (RR-DPU-56-C at WP G-28.1). To determine the proposed adjustment, the Company first divided the January 1, 2007, balance of plant accounts subject to property tax of $50,964,852 into the sum of tax payments made during the related assessment period of $910,324, thereby deriving a property tax ratio of 0.018192 (Exhs. NEGC-JMS at 22; NEGC-JMS-3, WP G-28.1; Tr. 6, at 752-753). The Company then multiplied this tax ratio of 0.018192 by its December 31, 2007, net plant subject to property taxes which resulted in a pro forma property tax of $927,153 (Exh. NEGC-JMS at 22; NEGC-JMS-3, WP G-28.1; Tr. 6, at 752-753). Subtracting the test year property taxes of $859,464 from the pro forma property tax of $927,153 results in the proposed increase of $67,688 (Exh. NEGC-JMS-3, WP G-28.1).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company incorrectly determined the average tax rate when calculating the level of pro forma property taxes (Attorney General Brief at 38). The Attorney General states that the Company determined the average property tax rate by dividing the property taxes for the year beginning July 2007 by the net plant balances as of

December 31, 2006 (id. citing Tr. 6, at 752-753). The Attorney General asserts that this method fails to recognize each property's actual assessed value as listed by each municipality for that period (id. citing Exh. NEGC-JMS-3, WP G-28.2). The Attorney General claims that the more appropriate approach is to divide total property taxes by the total assessed values of the taxed proprieties, as this would better match property taxes with test year-end rate base (id. citing Exh. NEGC-JMS-3, WPs G-28.3, G-28.4).

b. Company

The Company states that the Attorney General's proposed calculation of property taxes would result in a decrease in the rate recovery of property taxes expense at a point in time when NEGC had actually increased its investment in plant and property (Company Brief at 94). Additionally, the Company asserts that the Attorney General's method is flawed because it is based on the relationship between taxes paid and the assessed value of plant (id.). NEGC argues that it is more accurate to calculate a ratio of the relationship between taxes paid and book value of plant, as this ratio is applied to book value in calculating a proxy for property taxes (id. at 94-95).

3. Analysis and Findings

The Department's general policy is to base property taxes on the most recent property tax bills a utility receives from the communities in which it has property. D.P.U. 96-50 (Phase I) at 109; D.P.U. 84-94, at 19. With respect to the Company's proposal to use its test year-end plant balances, the Department is unpersuaded that the Company's net book value provides a reliable measure of valuation for property tax purposes. Therefore, we decline to adopt the Company's proposed property tax calculation. Similarly, because the evidentiary record includes actual property tax bill data for NEGC, we decline to adopt the Attorney General's computation.

Based on the most recent property tax billings furnished by the Company, the Department finds NEGC's property tax expense to be $956,866 (Exh. AG 1-84).[90] This represents an increase from test year property tax expense of $97,402. Accordingly, the Company's proposed cost of service will be increased by $32,040.

O. New England Gas Appliance Company

1. Introduction

NE Appliances is a wholly-owned subsidiary of SUG (Exh. NEGC-JMS at 7). During the test year, NE Appliances recorded $2,784,564 in below-the-line revenues associated with the rental of water heaters and conversion burners (Exhs. NEGC-JMS at 7; AG 1-30). Although NE Appliances maintains its own books, records, and employees, it receives a variety of services from NEGC, such as customer billing costs, rent, electricity, property taxes, and administrative payroll and related costs (Exh. NEGC-JMS at 8). Therefore, the Company allocates a portion of these costs to NE Appliances (id.; Exh. AG 1-27). During the test year, NEGC allocated $192,000 in costs to NE Appliances (Exh. NEGC-JMS-2, Sch. G-29).

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90 The Department calculated this property tax expense by taking the most current quarter shown in each tax bill represented in Exhibit AG 1-84, with the exception of property taxes from Plainville, and multiplied these by four quarters. Because the property taxes issued by the Town of Plainville appear to be based on semi-annual billings, we multiplied the current tax bills associated with this community by two.

The Company relies on causal allocation factors for customer-, employee-, and office-based expenses (Exhs. NEGC-JMS at 23; NEGC-JMS-3, WP G-29.4). For other expenses, the Company uses a three-part allocation formula consisting of margin, expenses, and investment and has proposed a 6.419 percent allocation factor (Exhs. NEGC-JMS at 23; NEGC-JMS-3, WP G-29.4). Because NEGC has allocated a portion of its warehouse, software, furniture and fixtures, and telecommunications equipment to NE Appliances, the Company's revenue requirement excludes any portion of return and income tax gross-up expense relative to the allocated plant items (Exh. NEGC-JMS at 23).

2. Analysis and Findings

Utilities frequently engage in non-utility related operations, including sale and rental of gas appliances, direct propane sales, and other activities. When such non-utility operations are above-the-line for ratemaking purposes, all revenues and expense associated with the program are included in the utility's revenue requirement. Commonwealth Gas Company, D.P.U. 87-122, at 16-25 (1987); D.P.U. 87-59, at 6-16. When the operation is below-the-line for ratemaking purposes, none of the revenues or expenses associated with the activity are included in the company's revenue requirement. D.P.U. 87-122, at 16-25; D.P.U. 87-59, at 6-16. Regardless of whether a company seeks above- or below-the-line ratemaking treatment for its non-utility operations, the Department seeks to ensure that ratepayer subsidization of non-utility operations does not occur. D.P.U. 87-59, at 10.

NE Appliances is a below-the-line activity (Exh. AG 1-30). Therefore, it is necessary to ensure that all direct and indirect costs of NE Appliances have been removed from NEGC's distribution rates. The Department has examined NEGC's allocations to NE Appliances (RR-DPU-56-A; RR-DPU-56-C, WPs G-29.1 through G-29.8). Based on our review, the Department finds that the Company has appropriately allocated costs to NE Appliances and that all expenses related to NE Appliances have been properly removed from NEGC's cost of service.

P. Inflation Allowance

1. Introduction

NEGC proposed an inflation adjustment of $115,541 (Exh. NEGC-JMS-2, Sch. G-30). The Company used the gross domestic product implicit price deflator ("GDPIPD") to calculate the inflation allowance (Exh. NEGC-JMS-2, Sch. G-30). The Company applied the GDPIPD from the midpoint of the test year to the midpoint of the rate year,[91] which resulted in a 5.1 percent inflation factor (id., Sch. G-30). The Company multiplied the inflation factor by its residual O&M expenses of $2,265,515, thus producing an inflation adjustment of $115,541 (id., Sch. G-30). The Company contends that its inflation adjustment complies with Department policy (Company Brief at 97). No other party addressed this issue on brief.

2. Analysis and Findings

The inflation allowance recognizes that known inflationary pressures tend to affect a company's expenses in a manner that can be measured reasonably. D.T.E. 02-24/25, at 184; D.T.E. 01-56, at 71; D.T.E. 98-51, at 100; D.T.E. 96-50 (Phase I) at 112; D.P.U. 95-40,

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91 The Company originally intended to submit its rate case filing in January of 2008; it was not, however, submitted until July of 2008. As such, the test year went from July 2007 to August 2009.

at 64. The inflation allowance is intended to adjust certain O&M expenses for inflation where the expenses are heterogenous in nature and include no single expense large enough to warrant specific focus and effort in adjusting. D.P.U. 1720, at 19-21. The Department permits utilities to increase their test year residual O&M expense by the projected GDPIPD from the midpoint of the test year to the midpoint of the rate year. D.P.U. 95-40, at 64; D.P.U. 92-250, at 97; D.P.U. 92-78, at 60. In order for the Department to allow a utility to recover an inflation adjustment, the utility must demonstrate that it has implemented cost containment measures. D.P.U. 96-50 (Phase I) at 113.

NEGC has undertaken a number of efforts to reduce healthcare costs (see, e.g., Exh. AG 1-52). These efforts include: (1) increasing the employee-cost share for non-union employees to 20 percent of the derived premium; (2) moving to a common carrier and a common platform for medical, dental, and vision plans under a self-funded arrangement; (3) adding three plan options to the medical benefits (90/70, 80/60, 70/60) and pricing the plans to encourage employees to take the lower-priced option; (4) requiring an employee contribution for union personnel in Fall River as a result of the recent contract negotiations; (5) maintaining an opt-out provision requiring verification of alternative insurance; and (6) for 2007, increasing the spread between the prescription drug co-pays to encourage the employees to take lower-cost generic drugs (id.). Accordingly, we find that NEGC has implemented cost containment measures.

In addition, the Company has calculated its proposed inflation allowance consistent with Department precedent. Thus, the Department finds that an inflation allowance adjustment equal to the most recent forecast of GDPIPD for the appropriate period as proposed by NEGC, applied to the Company's approved level of residual O&M expenses, is proper in this case. Accordingly, the Department accepts the proposed inflation allowance. See Table 1.

TABLE 1

Test Year Total, Excluding Purchase Gas		$20,300,924
Less Normalizing Adjustments Items		
Payroll Expense	$7,050,181	
Employee Benefits	4,570,472	
Transportation Clearing	652,969	
Compressor Station Expense	124,143	
Uncollectible Expense	1,571,569	
Customer Billing and Accounting Expense	1,765,052	
Postage Expense	263,622	
Service Charge Credits	(126,661)	
RCS Expense	26,111	
Professional Fees	(82,351)	
Management Fees	1,223,663	
Telecommunications Expense	202,091	
Insurance Premiums	180,241	
Injuries and Damages	493,716	
Rate Case Expense	61,232	
DPU Regulatory Assessment	100,384	
Rents and Leases	48,067	
Relocation Costs	20,195	
Advertising and Dues	8,090	
Miscellaneous Expense Reclassifications	71,893	
Applicance Company Allocations	(192,000)	$18,032,679
LESS: ITEMS NOT SUBJECT TO INFLATION		
Pension PBOP	$1,623,054	$1,623,054
Residual O&M Expenses		$645,191
Projected Inflation Rate		5.10%
Inflation Allowance		$32,905

Q. Strike Contingency

1. Introduction

The Company's current collective bargaining agreement took effect on May 1, 2006 (Exh. AG 1-42). During 2006, the Company incurred strike contingency costs (Exh. AG 5-28; Tr. 5, at 666).[92] The Company booked the expense to a deferred account and proposes to amortize the expense over a four-year period (i.e., the life of the contract) (Exh. AG 5-28, Tr. 5, at 666-667). As such, during the test year, NEGC booked $14,594 in strike contingency costs (Exhs. AG 1-65, Att. A at 1; AG 5-28).

2. Positions of the Parties

a. Attorney General

The Attorney General states that the Company's strike contingency expenses occurred during the period January through April 2006 (Attorney General Brief at 43, citing Exh. AG 5-28; Tr. 5, at 665-666). The Attorney General contends that these O&M expenses were incurred before the beginning of the calender year 2007 test year in this case (id.). The Attorney General also asserts that because the strike contingency costs were incurred to benefit NEGC and its shareholders during the four-month period when the union contract was being negotiated, these costs should have been expensed during that time (id.). The Attorney General further contends that the Company did not seek, and the Department did not make, an accounting ruling approving either the deferral or the recovery of these costs (id. citing Tr. 5,

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92 Strike contingency costs include items such as: (1) training non-union staff on the use of crucial equipment necessary to ensure continuation of safe operations; (2) developing customer information programs; and (3) implementing security measures.

at 667, 669). For these reasons, the Attorney General argues that the Department should remove the strike contingency costs of $14,594 from NEGC's pro forma cost of service (id.).

b. Company

The Company argues that the benefit of the strike contingency expenses was not limited to the few months in which they were incurred; rather, incurrence of these costs was necessary to remove the threat that strike contract negotiations would disrupt the provision of safe and reliable gas service (Company Brief at 98; Company Reply Brief at 16). NEGC also asserts that the costs represent reasonable, necessary, and recurring costs associated with periodic negotiation of the union contract, which is in effect for four years (Company Brief at 98). Thus, the Company argues that these costs provide a benefit over the entire four years of the union contract (id.; Company Reply Brief at 16-17). In response to the Attorney General's argument that NEGC failed to seek an accounting ruling, the Company asserts that this expenditure carries multi-year benefits and that under generally-accepted accounting principles, this type of deferral does not require an accounting authorization from the Department (Company Brief at 98-99, citing RR-AG-28).

3. Analysis and Findings

The strike contingency costs incurred during the most recent union contract negotiation were charged to Account 186000048 prior to the test year and are being amortized to Account 92300007 - Outside Services at the rate of $1,216.21 per month over the life of the current contract (Exh. AG 5-28). No adjustment was made to the test year expense of $14,594 so that the cost of service would include a normalized level of this recurring cost (id.).

The Company contends that strike contingency costs do not require specific authorization from the Department in order to be deferred on the Company's books (RR-AG-28). Pursuant to Statement of Financial Accounting Concepts No. 6, companies require regulatory approval to defer single-period costs such as conservation program costs; however, because strike contingency costs provide benefit to a company over multiple periods, Department approval is not required for the Company to defer those costs on its books.

Preparation for a potential labor strike is essential to ensure that the Company continues to operate in the event of a strike. Moreover, the Company will need to update or develop new strike contingency plans each time it negotiates a labor contract. Therefore, the Department finds $14,594 in strike contingency expenses to be recurring. The Department further finds that this amount is reasonable and necessary to adequately prepare for a potential labor strike. As such, the Department will allow the inclusion of the strike contingency expenses in NEGC's cost of service.

V. QUALITY OF SERVICE

A. Customer Service

1. Introduction

Customer calls of a general or routine nature are answered by NCO Financial, a professional call center located in Cannonsburg, Pennsylvania (Exh. UWUA 1-29; Tr. 1, at 142).[93] More complex credit and collection issues (e.g., payment on an old account, signing

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[93] The customer call center was previously located in Cumberland, Rhode Island, and served all of NEGC's operations in New England (Exh. UWUA 1-30). The call center (continued...)

a Cromwell waiver,[94] providing some needed documentation) are referred back to NEGC's Credit and Collections Department located at its Fall River office (Exh. UWUA 1-33; Tr. 1, at 143). According to the Company, the Credit and Collections Department is open Monday through Friday between 10:00 A.M. and 3:00 P.M. and does not handle cash transactions (Exh. UWUA 1-33; Tr. 1, at 124). The Company maintains a number of pay stations, such as local variety stores and pharmacies, where customers can pay their bills (see Exh. UWUA 1-32). Emergency calls are handled through the Company's Service Department office located at its Fall River office (Exh. UWUA 1-29).

2. Positions of the Parties

a. Local 431

Local 431 contends that the out-of-state call center operators are unfamiliar with Massachusetts statutes and regulations, such as consumer protection regulations regarding arrearages, termination of service, and restoration of service (Local 431 Brief at 5, citing Tr. A at 16, 119, 120, 122). Local 431 claims that the Company is not sufficiently familiar with the Department's billing and termination rules and that NEGC does not provide the call

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93 (…continued)
function was outsourced in August 2006 when NEGC sold its Rhode Island assets (id.).

94 "Cromwell waivers" arise from the Department's decision in Cromwell v. Boston Gas Company, D.P.U. 18123 (1974). In that decision, the Department established the principle that a customer who is current on bills for service at their current address cannot be terminated for failure to have made payment for service provided by the same company, but at a prior address. Thus, the term "Cromwell right" has evolved to express the right not to be terminated at one's current address for failure to pay for service at a prior address (Local 431 Brief at 9).

center employees with adequate training on Massachusetts rules (id. at 6, citing Exh. UWUA 1-31, RR-UWUA-5, Att. B; Local 431 Reply Brief at 4).[95] Local 431 concludes that, as a result, NEGC has a significantly worse consumer complaint record at the Department than any other gas LDC in Massachusetts (Local 431 Brief at 8, citing Exh. UWUA-6).

Therefore, Local 431 requests that the Department order NEGC to file a report within 30 days of the issuance of this Order as to how the Company will train the call center operators on Massachusetts statutes and regulations (id.). Local 431 also requests that the Department direct the Company to submit its training materials for call center operators to the Department for review (id.; Local 431 Reply Brief at 4).

Local 431 also alleges that the Company's customers have difficulty in obtaining Cromwell waivers to establish service at a new address (Local 431 Brief at 9). According to Local 431, Cromwell waivers are essential for a substantial number of low-income customers who are trying to establish service at a new address but who still owe money from a prior address (id.). Local 431 claims that unless the Company accepts a Cromwell waiver, the Company will require a full payment of the arrears from a prior address (id. citing RR-UWUA-5, Att. B). Therefore, Local 431 requests that the Department order NEGC to file a plan within 30 days after issuance of this Order, describing how it will expand the hours

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95 According to Local 431, the call center operators are not being given adequate training (Local 431 Brief at 7, citing RR-UWUA-5). For example, Local 431 notes that the training materials fail to clearly state that Massachusetts statues and regulations require that the Company offer customers a minimum payment plan of four months and, therefore, that an initial payment of 25 percent is sufficient to avert termination and initiate a payment plan (id. citing Exh. UWUA 1-31).

during which Cromwell waivers can be signed at Company offices or elsewhere (id. at 10; Local 431 Reply Brief at 4-5). Local 431 further argues that the Company should be required to make arrangements with Citizens for Citizens ("CFC"), the Fall River-based fuel assistance agency, so that Cromwell waivers may be signed at the CFC's offices and forwarded to NEGC (Local 431 Brief at 10-11; Local 431 Reply Brief at 5 n.4).

Local 431 also alleges that NEGC customers may not make payments at the Company's offices and are instead directed to third-party pay stations (Local 431 Brief at 11 citing Tr. A, at 16; Tr. 1, at 128). Local 431 states that when a customer makes a payment at a third-party pay station, there is delay in the Company being notified of the payment (id.). According to Local 431, this arrangement almost certainly delays restoration of service for customers whose service has been terminated and who are making a payment to obtain service restoration (id.). Therefore, Local 431 recommends that the Department direct the Company to accept payments at its offices and to file a plan within 30 days of issuance of this Order as to how and when it will begin accepting such payments (id.; Local 431 Reply Brief at 4-5).

Local 431 claims that NEGC has a dismal customer complaint history (Local 431 Brief at 11). Local 431 states that the complaints filed with the Department's Consumer Division equate to a complaint rate in Fall River of one complaint case for every 342 customers and a complaint rate in North Attleboro of one complaint case for every 225 customers (id. at 11-12, citing Exh. UWUA-6). Local 431 recommends that the Department give substantial weight to the service quality issues raised in this proceeding when setting the allowed return on common equity and that the rate of return be set at the low end of the "range of reasonableness" given the Company's performance (id. at 12, 20; Local 431 Reply Brief at 6).

b. Company

The Company disputes Local 431's claims and cites its annual service quality report for 2007 as demonstrating that NEGC has either met or exceeded its historic benchmarks for all of its service quality metrics with the exception of Consumer Division cases and the Fall River service area's billing adjustment statistics (Company Brief at 121-122, citing Annual Service Quality Report submitted on March 1, 2008, as part of 2008 Annual Service Quality, D.P.U. 08-22).[96] The Company claims that its performance for these two particular service quality metrics is merely indicative of increased customer activity during a year of high energy prices and in no way supports a finding of deficient service quality (id. at 122; Company Reply Brief at 33).

Additionally, NEGC notes that Local 431 failed to offer any expert witness to rebut the Company's proposed cost of common equity and contends that Local 431's concerns do not rise to a level of significance (Company Reply Brief at 32-33). The Company adds that penalizing it based on a service quality metric (i.e., customer complaints), which is largely beyond the Company's control, is ludicrous and would serve to undermine NEGC's efforts to meet its required cost of service (id. at 33-34).

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[96] The Company requests that the Department incorporate by reference the Company's filing in D.P.U. 08-22 (Company Brief at 121 n.25, citing 220 C.M.R. § 1.10(3)). No party objected to this request; thus, we are incorporating the document into the record.

3. Analysis and Findings

Regulated utilities have a fundamental obligation to comply with all Department regulations, including those contained in the Department's Billing and Termination Procedures at C.M.R. § 25.00 et seq. The Company's argument that the number of customer complaints is not a relevant metric implies that if the Department's service quality ("SQ") measures are being met, there can be, by definition, no service quality problem. The Company is mistaken on this point. The Department's SQ measures are intended to focus on key areas of a utility's performance as valid indicators of overall SQ; as we have acknowledged, not every area of customer service can or need be measured, assuming a properly chosen subset has been selected for the purpose. Service Quality Guidelines, D.T.E. 99-84, at 43 (August 17, 2000). The underlying premise here is that if a company is meeting its SQ performance measures in a satisfactory manner, then that company is in all likelihood performing well in other areas not included under the SQ performance measures – in the absence of other evidence to the contrary.[97]

Local 431 has raised various issues regarding the Company's customer call center, Cromwell waivers, and third-party pay stations. Local 431 has also identified the Company's customer complaint performance as further justification for granting a return on common equity at the lower range of reasonability. NEGC offered no specific response to these claims

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[97] Nowhere in the Department's SQ guidelines contained originally in D.T.E. 99-84, or as revised in Service Quality Guidelines, D.T.E. 04-116-B (2006), is there any inference that satisfactory performance under these SQ guidelines absolves a company from meeting its other customer-related obligations.

beyond generalized statements about its compliance with the Department's SQ guidelines and a possible cause for the number of customer complaints.[98] At the very least, we must find that the testimony and evidence support the finding that the practices at issue are acknowledged to be true. Commonwealth Electric Company, D.P.U. 84-114, at 10 (1984).

Many of the problems identified by Local 431 appear to be the result of NCO Financial's unfamiliarity with Massachusetts statutes and Department regulations. While the Department declines to intercede in management decisions as to the best way to meet NEGC's call center needs, call center employees (whether direct or through outsourcing) are obligated to be familiar with applicable statutes and regulations. See Witches Brook Water Company, D.T.E. 03-81, at 7-8 (2003).

Based on the foregoing, the Department finds that corrective measures are necessary and appropriate. See D.P.U. 84-114, at 11. By doing so, our intention is to ensure that customers receive the level of service to which they are entitled.

First, NEGC is ordered to file a report within 30 days of the issuance of this Order as to how the Company will train the call center employees of NCO Financial on Massachusetts statutes and regulations. The Company shall submit these training materials to the

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[98] As to NEGC's argument that Local 431 failed to offer any expert witness to rebut the Company's proposed return on equity, we note that the burden of proof to demonstrate the appropriateness of all aspects of the Company's filing lies with NEGC and not with Local 431 or any other intervenor. See, e.g., Fitchburg Gas and Electric Light Company, D.P.U. 99-118, at 9 (2001); New England Telephone and Telegraph Company, D.P.U. 94-50, at 287-289, 413-414 (1995); D.P.U. 93-60, at 26.

Department, and to the parties in this case, 30 days prior to using those materials for call center employee training.

Second, NEGC is ordered to file a plan within 30 days after issuance of this Order describing how it will expand the hours during which Cromwell waivers can be signed at Company offices or elsewhere. As part of this plan, the Department strongly encourages the Company to make suitable arrangements with CFC to allow for the signing of Cromwell waivers at CFC's offices in Fall River.

Third, NEGC is directed to file a study within 30 days of issuance of this Order describing the feasibility of receiving payments at its offices. Such study will include the expense incurred to undertake such a procedure, how the procedure would be implemented, and the timeframe in which the procedure would be implemented.

Fourth, NEGC is directed to work with its third-party pay stations to determine the feasibility of implementing a procedure by which the Company would be informed of payments on a daily basis.

Furthermore, as outlined below in Section VI.G., the Department will take NEGC's customer service deficiencies into consideration in its determination of the appropriate return on equity. See, e.g., D.P.U. 07-71, at 139-140; D.T.E. 02-24/25, at 230-231; D.P.U. 92-250, at 161-162; D.P.U. 85-266-A/271-A at 171-172.

B. Gas Leaks

1. Introduction

Gas leaks are placed into three categories: (1) Grade 1 leaks, which represent an existing or probable hazard to persons or property and require immediate repair or continuous action until the conditions are no longer hazardous; (2) Grade 2 leaks, which are recognized as being non-hazardous at the time of detection but justify scheduled repair based on probable future hazard; and (3) Grade 3 leaks, which are non-hazardous at the time of detection and can reasonably be expected to remain non-hazardous (Exh. UWUA 1-6, Att; Tr. 1, at 83-84). As of September 16, 2008, NEGC reported that there were zero unresolved Grade 1 leaks, 49 unresolved Grade 2 leaks, and 372 unresolved Grade 3 leaks (Exh. UWUA 1-7, Att.).

2. Positions of the Parties

a. Local 431

Local 431 contends that NEGC's failure to promptly address gas leaks can place the safety of the public and Company employees at risk (Local 431 Brief at 13). Local 431 contends that unresolved Grade 2 leaks have increased by 250 percent during the first nine months of 2008 (id.; Local 431 Reply Brief at 6). Local 431 also asserts that NEGC does not have the appropriate tools to monitor leaks and determine whether there are upward trends in certain types of leaks (Local 431 Brief at 13). Local 431 asks the Department to direct the Company to develop tracking tools, such as time series charts, and to submit a report to the Department outlining its proposal for reducing a backlog of unresolved Grade 2 leaks (id. at 14; Local 431 Reply Brief at 6 n.6).

b. Company

NEGC contends that any unrepaired leaks are considered non-hazardous (Company Brief at 122). The Company states that most of the unrepaired leaks are Grade 3, which are given the lowest priority over other leaks because they are unlikely to become a safety threat (id. citing Tr. 1, at 84-86). Thus, NEGC contends that Local 431's assertions should be given no weight (id.). Moreover, the Company asserts that any issue raised by Local 431 on this matter does not rise to a level of significance such that NEGC's revenue requirement or cost of equity in this proceeding should be impacted (Company Reply Brief at 32).

3. Analysis and Findings

In monitoring gas leaks, the Department is guided by federal pipeline safety regulations contained in 49 C.F.R. Part 192, Section 192.703, which requires hazardous leaks to be repaired promptly. Consistent with industry practice, Grade 1 leaks are the only hazardous classification and the Company has demonstrated that it has no unrepaired Grade 1 leaks (Exh. UWUA 1-7, Att.). Pursuant to Department requirements, Grade 2 leaks are generally scheduled for repair with six to 18 months of discovery. Grade 3 leaks are not generally scheduled for repair. Nonetheless, both Grade 2 and Grade 3 leaks should be periodically checked to see if they have become hazardous. See, e.g., 47 C.F.R. §§ 192.605, 192.615. The record shows that NEGC appropriately monitors the Grade 2 and Grade 3 leaks (see generally Exh. UWUA 1-7, Att.).

The Department notes that the eight month period over which Local 431 cited the increase in leak backlog extended from winter into early fall. During at least three of those months, January through March, most cities and towns have a moratorium on street openings. The only exception to these moratoriums is for emergencies. As such, NEGC would be unable to repair any Grade 2 and Grade 3 leaks detected during those months. Nonetheless, the Department's Pipeline Engineering and Safety Division enforces federal and state pipeline safety regulations and will continue to regularly inspect NEGC's operations, maintenance, and facilities for compliance and safety.

C. Abandoned Service Lines

1. Introduction

The Department requires each gas LDC to prepare and follow written procedures for the inactivation and abandonment of service lines. 220 C.M.R. § 107.04. Pursuant to this requirement, the Company tracks abandoned services lines that have been cut off and capped at the main but that have not been capped inside of the buildings (Exh. UWUA 1-24, Att.). As of mid-September 2008, the Company reported that there were approximately 740 such abandoned service lines (id., Att.).

2. Positions of the Parties

a. Local 431

Local 431 asserts that NEGC is not appropriately abandoning gas service lines (Local 431 Brief at 14). Specifically, Local 431 states that the Company is failing to cap the service lines inside of the buildings (id. at 14-15). Local 431 asserts that there are approximately 1,000 abandoned service lines that have been cut off and capped at the main but that have not been capped inside of the buildings (id.). Local 431 requests that the Department order the Company to submit a proposal outlining its plan to reduce the number of uncapped service lines over the next twelve months (id. at 15).

b. Company

NEGC asserts that it always makes an effort to cap abandoned lines inside buildings (Company Brief at 123, citing Tr. 1, at 88). NEGC contends, however, that at times customers will not give the Company access to buildings (id. citing Tr. 1, at 89, 92). NEGC also contends that, in many instances, the gas lines were serving buildings that have since been demolished and, therefore, there is no inside service line to cap (id.). The Company argues that as long as the service line has been cut at the main, there is no public safety hazard (id.).

3. Analysis and Findings

The Department's regulation on the abandonment of inactive service lines states, in pertinent part, "abandoned means that: (a) the service line is disconnected or cut off at or as close as practical to the main; (b) any opening in the main or the open end of the segment of the service line left thereto is sealed; (c) the service line is purged of gas, except when the volume of gas is so small that there is no potential hazard; and (d) the open end of the disconnected service line near the main and traversing to the premises is sealed." 220 C.M.R. § 107.03. The regulation does not require that an abandoned service line be capped inside of the building because such practice is not hazardous to public safety.

The Department finds that NEGC's practices regarding the abandonment of service lines are consistent with the Department's regulations (Exh. UWUA 1-24). As such, we will not require the Company to take further action at this time.

VI. CAPITAL STRUCTURE AND RATE OF RETURN

A. Introduction

NEGC proposed an 8.82 percent WACC, representing the rate of return to be applied on rate base to determine the Company's total return on its investment (Exhs. NEGC-FJH at 2-3, 65; DPU 4-13; Tr. 3, at 309-310). This rate is based on: (1) a proposed hypothetical capital structure[99] that consists of 53.0 percent long-term debt and 47.0 percent common equity; (2) a proposed cost of long-term debt of 6.35 percent; and (3) a proposed rate of return on common equity of 11.60 percent (Exhs. NEGC-FJH at 2-3, 19-20; NEGC-FJH-1, Sch. 1, at 1).[100] The individual components of the Company's proposal are discussed below.

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[99] A hypothetical capital structure represents a capital structure that differs from that of the company being examined. At times, a hypothetical capital structure may be used for ratemaking purposes if the actual company's capitalization deviates substantially from sound and well-established utility practice, or where the actual capital structure is illogical, such as may be found in the case of a small system with negative common equity arising from significant operating losses. See, e.g., D.T.E. 03-40, at 320, 322; Kings Grant Water Company, D.P.U. 87-228, at 21-22 (1988); Witches Brook Water Company, D.P.U. 1220/1220-I, at 14 (1983).

[100] In its initial filing, NEGC also proposed an 8.73 percent WACC based on an 11.40 percent cost of common equity assuming approval of the Company's proposed revenue decoupling mechanism (Exhs. NEGC-FJH at 2-3, 63-65; DPU 4-13; Tr. 3, at 309-310). In New England Gas Company, D.P.U. 08-35, Interlocutory Order on Scope of Proceeding and Request of the Attorney General and New England Gas Company to Bifurcate at 6 (2008), the Department found that the Company was not eligible to file a decoupling mechanism at this time and that the Department was unable to consider in the instant docket NEGC's revenue decoupling mechanism proposal. See also Tr. 3, at 337.

B. Comparison Group

1. Description

As a basis for determining its proposed capital structure, cost of debt, and cost of common equity, the Company selected nine gas distribution companies from Value Line Investment Survey (Standard Edition) ("Value Line") as a comparison group and analyzed the financial data on these companies (Exhs. NEGC-FJH at 5, 15-18; NEGC-FJH-1, Sch. 3).[101] The Company explained that NEGC, being one of the several operating divisions of SUG, has no common stock that is publicly traded (Exh. NEGC-FJH at 4; Tr. 3, at 315). The Company added that although SUG has publicly-traded common stock, SUG is not an appropriate vehicle for developing the Company's cost of capital because investors no longer view SUG as a gas distribution company (Exh. NEGC-FJH at 4; Tr. 3, at 319).[102]

The Company provided for the years 2003 to 2007 financial and operating data for the individual companies in the comparison group, for the Fall River and North Attleboro service areas of NEGC, and for NEGC as a whole (Exhs. NEGC-FJH at 16; NEGC-FJH-1, Sch. 3,

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101 The companies included in the comparison group are AGL Resources Inc., Atmos Energy Corporation, The Laclede Group, Inc., NICOR Inc., Northwest Natural Gas Company, Piedmont Natural Gas Company, Inc., South Jersey Industries, Inc., Southwest Gas Corporation, and WGL Holdings, Inc. (Exh. NEGC-FJH-1, Sch. 3, at 2).

102 The Company noted that SUG's stated goal is the transformation from a utility to a natural gas transportation and services company (Exhs. NEGC-FJH at 4; DPU 4-12; Tr. 3, at 319). The Company indicated that SUG's previous sale of its PG Energy division to UGI Utilities, Inc., the sale of the Rhode Island assets of SUG's NEGC division to National Grid PLC, and SUG's acquisition of Sid Richardson Energy Services are part of this continuing transformation of SUG (Exhs. NEGC-FJH at 4, 19; DPU 4-12, Att.; DPU 4-21, Att.).

at 1, 5-8). The Company also provided for each company in the comparison group its historical earnings per share, book value per share, and dividend per share growth rates as well as long-term earnings per share growth rate projections (Exhs. NEGC-FJH at 18; NEGC-FJH-1, Sch. 3, at 9).

2. Positions of the Parties

a. Attorney General

The Attorney General claims that there is no difference between the analyses in the Company's current filing and those rejected by the Department in the past, except for the companies that comprise the comparison group and the updated numbers (Attorney General Brief at 47). The Attorney General contends that the Company failed to recognize the higher business risk of the companies in the comparison group, thus overstating the cost of capital for the comparison group and, therefore, the analysis should be rejected (id.).

More specifically, the Attorney General notes that most of the companies in the comparison group have investments in other businesses that affect their risk profile (id. at 48, citing Exhs. NEGC-FJH-1, Sch. 3, at 6; AG 7-15; Attorney General Reply Brief at 32). The Attorney General claims that the Company ignored these non-gas distribution businesses and the added risks they imposed, and argues that these added risks biased upward the recommended cost of equity (Attorney General Brief at 49; Attorney General Reply Brief at 32).

The Attorney General rejects the Company's claim that the business risk of the companies in the comparison group is comparable to that of NEGC (Attorney General Reply

Brief at 31-32, citing Company Brief at 105-106). Contrary to the Company's position, the Attorney General contends that non-gas distribution revenues and other business operations of the companies in the comparison group are relevant and form part of the risk and earnings analysis of investment analysts (id. citing Exh. NEGC-FJH-1, Sch. 11).

b. Company

In selecting the companies in the comparison group, the Company argues that it is appropriate to observe the market-based common equity cost rates of other gas distribution companies, whose common stocks are actively traded, as a proxy to derive a recommended cost of capital and capital structure (Company Brief at 105-106, citing Exh. NEGC-FJH at 4).[103] The Company asserts that the use of other firms with comparable risks as proxies is consistent with the principles of fair rate of return established in Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) ("Hope"), and Bluefield Waterworks Improvement Company v. Public Service Commission, 262 U.S. 679 (1922) ("Bluefield") (Company Brief at 103, 105-106). The Company argues that, consistent with the principles of

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103 The criteria used by the Company in selecting the nine gas distribution companies in the comparison group require companies that: (1) are included in Value Line's natural gas distribution industry; (2) have actively traded common stock; (3) have not cut or omitted their common stock dividend during the five calendar years ending 2007 and up to the time of the preparation of the direct testimony by NEGC's cost of capital witness; (4) at the time of the preparation of such a direct testimony had not announced any merger or acquisition plans; (5) in 2007, had at least 50 percent of revenues and at least 50 percent of net operating income as well as assets derived from 2007 gas distribution operations; and (6) are included in S&P's Compustat PC Plus Research Insight Database (Exhs. NEGC-FJH at 15; NEGC-FJH-1, Sch. 3, at 2). The S&P Compustat PC Plus provides software and data retrieval system designed for financial analysis (Exh. DPU 4-24). The S&P Compustat database contains financial, statistical, and market data for United States and Canadian corporations (Exh. DPU 4-24).

fair rate of return established in Hope and Bluefield, the gas distribution companies included in the comparison group met the specified criteria for the selection of comparable companies (Company Reply Brief at 22, citing Exh. NEGC-FJH at 15). The Company rejects the Attorney General's argument that the companies in the comparison group are riskier and have higher returns that render those companies inadequate to serve as basis for setting the rate of return on equity for NEGC (Company Brief at 106).

In addition, the Company claims that the Department has recognized that it is neither necessary nor possible to find a comparison group of companies that matches a distribution company in every detail (Company Brief at 106, citing D.T.E. 03-40, at 355; Company Reply Brief at 22-23). The Company adds that, instead, the Department has relied on an analysis that employs valid criteria to determine which utilities will be in the comparison group, along with sufficient financial and operating data to discern the investment risk of the subject distribution company versus the comparison group (Company Brief at 106, citing D.P.U. 07-71, at 134-135; Company Reply Brief at 23).

The Company argues that the companies in the comparison group are larger than NEGC and have tariffs that mitigate the vagaries of weather and declining use per customer, which results in less business risk than NEGC (Company Reply Brief at 23). Finally, the Company claims that the Attorney General's arguments are inconsistent (id.). That is, she argues that the comparison group companies derive some revenues outside of gas distribution and, therefore, are inappropriate to rely on as basis for setting the rate of return on equity for NEGC, and, at the same time, she argues that the Department should use SUG's capital structure in setting the Company's return on equity (id. citing Exh. NEGC-FJH at 19; Tr. 3, at 366).

3. Analysis and Findings

The Department has accepted the use of a comparison group of companies for evaluation of a cost of equity analysis when a distribution company does not have a common stock that is publicly traded. See Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 80-82 (2001); D.P.U. 92-78, at 95-96. The Department has stated that companies in the comparison group must have common stock that is publicly traded and must be generally of comparable investment risk. Western Massachusetts Electric Company, D.P.U. 1300, at 97 (1983). Although the common stock of SUG is publicly traded, return on equity models typically rely on the analysis of a comparison group for consistency with the standards set forth in Hope and Bluefield. See D.P.U. 87-59, at 62; D.P.U. 85-266-A/271-A at 154.

In our evaluation of the comparison group used by the Company, we recognize that it is neither necessary nor possible to find a group that matches the Company in every detail. See D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; Boston Gas Company, D.P.U. 1100, at 135-136 (1982). Rather, we may rely on an analysis that employs valid criteria to determine which utilities will be in the comparison group and then provides sufficient financial and operating data to discern the investment risk of the Company versus the comparison group. See D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; D.P.U. 1100, at 135-136.

We find NEGC has employed valid criteria to select its comparison group and has provided sufficient information about the comparison group to allow the Department to draw conclusions about the relative risk characteristics of the Company versus the members of the comparison group (Exh. NEGC-FJH-1, Sch. 3). We will, therefore, accept the Company's use of a comparison group of companies with publicly traded stocks as a basis for its cost of capital proposal. The Department, however, notes that the Company's comparison group includes utilities that are involved in non-regulated businesses beyond gas distribution that could make these companies relatively more risky and, in turn, potentially more profitable. As discussed below, we will take this factor into consideration in determining the appropriate rate of return on common equity for NEGC.

C. Capital Structure and Costs of Preferred Stock and Long-Term Debt

1. Description

The Fall River and North Attleboro divisions of NEGC do not have their own capital structure, common stock, or long-term debt (Tr. 6, at 769-770).[104] Accordingly, the Company proposed a hypothetical capital structure, derived from the comparison group of gas distribution companies (Exh. NEGC-FJH at 19-20). Based on total permanent capital, that includes long-term debt, common equity, and preferred stock but excludes short-term debt, the common equity ratios for the comparison group of companies range from 50 percent to 53 percent (id. at 20; Exh. NEGC-FJH-1, Sch. 5, at 1; Tr. 3, 367-369). The Company noted

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[104] After NEGC was acquired by SUG on September 28, 2000, all of the balances in the books of FRG and NAG were eliminated in the process of consolidation (Tr. 6, at 770). The Company noted, for example, that the Fall River service area's balances under common stock, premium on common stock, and investments in associated companies, as shown in the 2007 annual return to the Department, represent the equity position of FRG at the time of its acquisition by SUG (Exh. AG 1-2, Att. A(1), at 8-9, 29; Tr. 6, at 769).

that the use of a lower common equity ratio of 47 percent, and a correspondingly higher debt ratio of 53 percent, results in a lower overall cost of capital and a lower revenue requirement due to a correspondingly lower provision for income tax (Exh. NEGC-FJH at 20-21; Tr. 3, 369-370).

The Company's proposed long-term debt cost rate of 6.35 percent is based on the average of the composite long-term debt interest rates of the nine gas distribution companies in the comparison group (Exhs. NEGC-FJH at 21-22; NEGC-FJH-1, Sch. 6, at 1). The Company determined this cost rate by first calculating the total annualized cost of debt and the composite interest rate for each of the nine companies in the comparison group based on each company's 2007 outstanding amounts of long-term debt and the corresponding interest rate for each debt series (Exhs. NEGC-FJH at 21-22; NEGC-FJH-1, Sch. 6, at 1). Then the Company took the average of the computed composite rates of the nine companies in the comparison group to arrive at the 6.20 percent long-term debt cost rate (Exhs. NEGC-FJH at 21-22; NEGC-FJH-1, Sch. 6, at 1).

The Company contends that the composite interest cost rates do not represent the full cost of raising long-term debt capital because there are associated issuance costs (Exhs. NEGC-FJH at 21-22; NEGC-FJH-1, Sch. 6, at 1). Accordingly, the Company proposed to add 15 basis points as provision for issuance costs (Exh. NEGC-FJH at 22). The Company added this 15 basis points to the 6.20 percent average composite long-term debt rate of the nine comparison companies to arrive at the proposed 6.35 percent long-term debt cost rate (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General recommends that the Department reject the Company's proposed hypothetical capital structure and instead use SUG's actual test year-end capital structure (Attorney General Brief at 46).[105] The Attorney General maintains that SUG's capital structure is different from the Company's proposed hypothetical structure and that using SUG's capital structure would significantly lower the cost of capital for NEGC (id. at 44).

The Attorney General notes that SUG's capital structure as of December 31, 2007, consists of 60.57 percent long-term debt, 4.00 percent preferred equity, and 35.43 percent common equity with the corresponding cost rates of 6.46 percent, 7.76 percent, and 11.60 percent,[106] respectively (id. at 45, citing Exhs. AG 7-1; NEGC-FJH at 3).[107] The Attorney General claims that based on this capital structure and its component cost rates,

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105 The Attorney General argues that the Department traditionally starts with a utility's own capital structure to set rates unless such structure deviates substantially from sound utility practice (Attorney General Reply Brief at 31, citing D.P.U. 07-71, at 141). The Attorney General contends that if NEGC wants to depart from this practice, the burden of demonstrating that something different is required rests on the Company and not on the Attorney General (id.).

106 For the purpose of her brief on this issue, the Attorney General relied on the 11.60 percent rate of return on common equity proposed by the Company absent the decoupling component.

107 The Attorney General contends that, although the Department found SUG's debt ratio of 65 percent in 2003 to be high, it is now down to 60 percent (Attorney General Reply Brief at 31). Accordingly, the Attorney General argues that the Company's position that such a ratio is inappropriate requires additional proof (id. citing Company Brief at 102, citing Southern Union Company, D.T.E. 03-3, at 16 (2003)).

SUG's actual overall WACC would be 8.34 percent after tax, and 11.19 percent before tax (id.). The Attorney General compares SUG's figures with the corresponding proposed 8.82 percent after-tax and 12.34 percent pre-tax weighted costs of capital produced by NEGC's proposed capital structure (id. at 45, citing Exh. NEGC-FJH at 3; RR-DPU-56, Sch. A at 2). Accordingly, the Attorney General claims that by using a hypothetical capital structure, the Company inflates its pre-tax weighted cost of capital by 1.15 percent and correspondingly increases its revenue requirement by $575,878 (id. at 46, citing RR-DPU-56, Sch. A at 2; Attorney General Reply at 31).[108]

The Attorney General claims that NEGC does not issue any of its own securities in the market and that SUG is the source of all financing for NEGC's operations except for the Company's financing from retained earnings (Attorney General Brief at 44). The Attorney General also claims that NEGC receives cash infusions from SUG, not through formal securities or agreements, but rather through the accounts payable line on the Company's balance sheet (id. citing Tr. 6, at 772-773). Accordingly, the Attorney General suggests that it would be appropriate for the Department to consider the costs of capital for SUG when determining the cost of service for the Company (id.).

108 The Attorney General calculated this 1.15 percent as the difference between a 12.34 percent pre-tax WACC based on the Company's proposal and the 11.19 percent pre-tax WACC using SUG's capital structure, costs of long-term debt and preferred security, and the Company's proposed rate of return on common equity (Attorney General Brief at 46). The Attorney General stated that the amount of $595,878 is equal to the product of 1.15 percent and the Company-proposed rate base of $51,890,479 (id. citing RR-DPU-56, Sch. A at 2).

Finally, the Attorney General argues that if the Department requires the use of SUG's actual capital structure to determine the overall cost of capital for NEGC, then it would be appropriate also to use SUG's cost rates for long-term debt and preferred equity (id. at 46, citing Exh. AG 7-1).

b. Company

NEGC argues that the Department normally accepts a distribution company's test year-end capital structure, allowing for known and measurable changes, unless the capital structure deviates substantially from sound utility practice (Company Brief at 101, citing D.T.E. 03-40, at 319; Company Reply Brief at 20). The Company asserts that the Department has looked unfavorably upon capital structures with a high long-term debt ratio and has previously found that SUG had an inappropriately high debt ratio (Company Brief at 102, citing Southern Union Company, D.T.E. 03-3, at 16 (2003); Company Reply Brief at 21).

The Company contends that, in this instance, SUG's actual capital structure deviates substantially from sound utility practice (Company Brief at 101; Company Reply Brief at 20). The Company adds that SUG's capital structure is unrepresentative of a gas distribution operation because of SUG's high level of reliance on revenues and earnings derived from sources other than gas distribution, which, thus, makes SUG much riskier than a typical gas distribution company (Company Brief at 101, citing Tr. 3, at 366; Company Reply Brief at 20-21).[109] The Company further notes that, as a division of SUG, NEGC has no meaningful

109 The Company, for example, represents that SUG's sale of its PG Energy division to UGI Utilities, Inc., and its Rhode Island assets to National Grid PLC are actions (continued...)

stand-alone capital structure because it has no common stock traded in the marketplace (Company Brief at 101).

Moreover, the Company asserts that a debt ratio of 60 percent is too high when compared to the average capital structure of the comparison group of companies with a debt ratio of 53 percent (Company Reply Brief at 21-22, citing Exhs. NEGC-FJH at 20; NEGC-FJH-1, Sch. 5 at 2). The Company argues that because there is no meaningful stand-alone capital structure for NEGC and SUG's capital structure is unrepresentative, the Department must use a hypothetical capital structure derived from the comparison group of gas distribution companies (Company Brief at 101-102). Noting that its proposed capital structure results in a lower overall cost of capital and lower revenue requirement, the Company concludes that the use of an hypothetical capital structure consisting of 53 percent long-term debt and 47 percent common equity is reasonable and consistent with Department precedent (id. at 102-103).

Claiming that as a matter of law the decision of the Department must be based on substantial evidence, the Company contends that the Attorney General failed to provide evidence to support her recommendation that SUG's capital structure is appropriate as a basis for setting rates for NEGC (id. at 100; Company Reply Brief at 20). The Company notes, for example, that even if SUG's actual capital structure were to be used, the Attorney General has

[109] (…continued)
consistent with SUG's goal of transforming to a natural gas transportation and services company (Company Brief at 101, citing Tr. 3, at 319; Company Reply Brief at 21).

not offered an expert witness to make the necessary adjustments to the capital structure to remove items such as goodwill (Company Brief at 102; Company Reply Brief at 20).

The Company states that the Department has typically relied for ratemaking purposes on a capital structure consisting of 50 percent debt and 50 percent common equity (Company Brief at 103, citing D.T.E. 03-40, at 324). The Company asserts that whether its debt ratio is 65 percent or 60 percent, that ratio is still too high for use in setting rates, and contends that the Attorney General failed to cite any case in which the Department has indicated that a debt ratio of 60 percent is appropriate to set rates for a gas utility (Company Reply Brief at 21).[110]

Turning to the cost of long-term debt, the Company urges the Department to reject the Attorney General's proposal to use SUG's actual long-term debt rate of 6.46 percent (Company Brief at 103-104). The Company argues that SUG's long-term debt is not appropriate to determine the long-term debt of the Company because SUG's capital costs are unrepresentative of a gas distribution operation (id. at 104). The Company notes, for example, that SUG's bond rating by Moody's and Standard and Poor's ("S&P's") are Baa3 and BBB-, respectively, while the average bond ratings for the comparison group are A3 and A for Moody's and S&P's, respectively (id.).

The Company defends its proposed rate of 6.35 percent, arguing that its 15 basis point addition to the composite costs of debts for its comparison group to allow for issuance cost is

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110 The Company noted, for example, that the Department had rejected the actual capital structure of Boston Gas Company, which had only 39.65 percent common equity and instead adopted a hypothetical capital structure with 50 percent common equity (Company Reply Brief at 21, citing D.T.E. 03-40, at 314, 325).

consistent with Department precedent, which allows for the inclusion of debt issuance costs in the long-term debt rate (id. at 104-105, citing D.T.E. 90-121, at 161). Finally, the Company observes that its proposed long-term debt cost of 6.35 percent is lower than the long term debt rate of 6.46 percent recommended by the Attorney General (id. at 105).

3. Analysis and Findings

A company's capital structure typically consists of long-term debt, preferred stock, and common equity. D.P.U. 07-71, at 122; D.T.E. 03-40, at 319; D.T.E. 01-56, at 97; Pinehills Water Company, D.T.E. 01-42, at 17-18 (2001). The ratio of each capital structure component to the total capital structure is used to weigh the cost (or return) of each capital structure component to derive a WACC. The WACC is used to calculate the return on rate base for calculating the appropriate debt service and profits for the company to be included in its revenue requirements. D.P.U. 07-71, at 122; D.T.E. 03-40, at 319; D.T.E. 01-42, at 18; D.P.U. 86-149, at 5.

The Department will normally accept a utility's test year-end capital structure, allowing for known and measurable changes, unless the capital structure deviates substantially from sound utility practice. D.T.E. 03-40, at 319; High Wood Water Company, D.P.U. 1360, at 26-27 (1983); Blackstone Gas Company, D.P.U. 1135, at 4 (1982). In reviewing and applying utility company capital structures, the Department seeks to protect ratepayers from the effect of excessive rates of return. D.T.E. 03-40, at 319; Assabet Water Company, D.P.U. 1415, at 11 (1983); D.P.U. 1135, at 4; see Mystic Valley Gas Company v. Department of Public Utilities, 359 Mass. 420, 430 n.14 (1971).[111]

In this case, the Company proposed a hypothetical capital structure consisting of 53 percent long-term debt and 47 percent common equity based on the capital structure of the nine companies in its comparison group. As of the end of the test year, December 31, 2007, SUG's actual permanent capital consisted of $3,395,006,000 in long-term debt, $230,000,000 in preferred securities, and $1,975,806,000 in common equity for a total permanent capital of $5,600,812,000 (Exh. AG 7-12, Att.). The corresponding capital structure ratios were 60.62 percent long-term debt, 4.10 percent preferred securities, and 35.28 percent common equity (id.; Exh. NEGC-FJH-1, Sch. 4, at 1). The cost of long-term debt was 6.46 percent and the cost of preferred securities was 7.76 percent (Exh. AG-7-1, Att.).

At the time of the 2000 merger, SUG was a natural gas LDC incorporated under the laws of the State of Delaware. See D.T.E. 00-25, at 25, 27; D.T.E. 00-26, at 24, 26. Currently, the former FRG and NAG are divisions of SUG operating in Massachusetts subject

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111 In 359 Mass. 420, 430 n.14, the Massachusetts Supreme Judicial Court noted:

> The use of a hypothetical capital structure has been adversely criticized, as, for example, by Professor James C. Bonbright, Principles of Public Utility Rates, 243-244. He there refers to the use of a hypothetical structure as substituting "an estimate of what the capital cost *would be* under non-existing conditions for what it *actually is or will soon be* under prevailing conditions." He recognizes, however, as we do, that "if the existing security structure is clearly unsound or . . . extravagantly conservative, the rule must be modified in the public interest," in which event "[a]ctual cost of capital may . . . be disqualified in favor of *legitimate* cost."

to the Department's jurisdiction. See D.T.E. 00-25, at 25, 27; D.T.E. 00-26, at 24, 26; D.P.U. 03-3, at 1 n.1.[112] SUG has investments in non-gas distribution and non-price regulated businesses and has announced a long-term goal of becoming a transportation and services company (Exhs. NEGC-FJH at 4; NEGC-FJH-1, Sch. 1, at 1 n.1; DPU 4-12, Att.). Also, as discussed in Section VI.B. above, the companies in the comparison group have investments and operations in non-gas distribution and non-price regulated businesses (Exh. DPU 4-28, Atts. A, B).[113] For example, AGL Resources and The Laclede Group are engaged in gas storage and marketing, and Nicor has shipping and other energy ventures (Exh. AG 7-15 (Att. B)).

Although the immediate need to raise additional external funds may have been related to various non-utility related projects, the financings were issued in the context of the particular company's entire financial circumstances at the time, including their embedded long-term capital structure, short-term debt limits, retained earnings, current earnings from operations, past and ongoing construction projects, and preferred and common stock dividend payments. For the Department to determine whether a given financing should be allocated specifically to utility or non-utility operations, it would be necessary to segregate SUG's entire

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112 SUG is not organized as a parent company with separate wholly-owned operating subsidiaries or "affiliates" having separate capital structures (Exh. AG 1-7). As a result, SUG's capital structure, capital ratios and costs of capital is consolidated for all operating divisions, with the exception of Panhandle Eastern Pipeline Company, which maintains a separate capital structure (id.).

113 Eight of the nine companies in the comparison group are holding companies and some companies operate in several states (e.g., AGL Resources, Inc. (five states) and Atmos Energy Company (13 states)) (RR-DPU-11; Tr. 3, at 444).

capital structure by tracing funds to the various operations. In this case, an equitable allocation of its capital structure would require that we attempt to determine the use of the proceeds of upwards of several billion dollars in long-term debt and stock that have been issued over a substantial number of years. We find this task in SUG's case to be exceedingly difficult, given the long period that SUG has been in operation, the fact that its utility and non-utility operations have been inextricably intertwined, and the fact that SUG was not even subject to the Department's jurisdiction until 2000. Further, even if it were possible to trace funds successfully, SUG's financial structure is not static. Cash is fungible, and future levels of revenues and expenses would alter any allocation of its capital structure between utility and non-utility operations. Fitchburg Gas and Electric Company, D.P.U. 1214-D at 4 (1985). Finally, we find that even if it were appropriate to undertake the proposed allocation of SUG's capital structure, the record is devoid of an appropriate methodology with which to separate accurately those funds.

Based on the evidence in this case, we cannot distinguish the financing of the gas distribution operations of the companies in the comparison group from the financing of the operations of their non-gas distribution and non-price regulated businesses. Similarly, we cannot discern the financing of the operations of NEGC from the financing of the other operations of SUG.[114] In D.T.E. 03-3, at 16-17, for example, the Department noted that with

114 The Department has previously noted that the Company's debt and equity financings are not specifically attributable to any particular jurisdiction. Southern Union Company, D.T.E. 02-27, at 14 n.15 (2002); Southern Union Company, D.T.E. 01-32, at 11 n.10 (2001).

the acquisition of Panhandle Eastern by SUG, the then-current debt ratio of 63.70 percent and equity ratio of 36.30 percent will change to approximately 73 percent and 27 percent, respectively. Nonetheless, having noted then that SUG would take steps thereafter to improve its capital structure, the Department stated that "because the resulting ratio's excursion from the norm will be transient and because the [c]ompany will be required to report to us quarterly on its efforts to make good its representation that it will soon reestablish a more conventional capital structure, we are willing to approve this § 17A request." Id. at 17.

In D.T.E. 03-40, at 322, the Department approved Boston Gas Company's proposal for a hypothetical 50 percent common equity ratio because the removal of goodwill[115] from its debt and equity capitalization resulted in a significant disparity between capitalization and rate base.[116] In addition, the Department determined that such a removal of goodwill along with other related capitalization adjustments, would have resulted in a relatively higher common

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115 An acquisition premium, or goodwill, is generally defined as representing the difference between the purchase price paid by a utility to acquire plant that previously had been placed into service and the net depreciated cost of the acquired plant to the previous owner. Mergers and Acquisitions, D.P.U. 93-167-A at 9 (1994).

116 In the past, the Department has allowed the removal of goodwill from capitalization because of its intangible nature that renders it inappropriate for consideration as a component in a utility's capitalization for purposes of G.L. c. 164, §§ 14, 16. Southern Union Company, D.T.E. 02-27, at 12 (2002); Southern Union Company, D.T.E. 01-32, at 11 (2001); New England Gas Company, D.T.E. 00-53, at 9 (2000), citing Boston Gas Company, D.P.U. 17138, at 7-8 (1971). The Department has noted the difference in the treatment of intangible capitalization, including acquisition premiums, for the unique purposes of the net plant test and its effect on capitalization, versus the Department's ratemaking authority embodied in G.L. c. 164, § 94. D.T.E. 03-40, at 320-322.

equity ratio of 66.11 percent, compared to the company-proposed 50 percent equity ratio.[117] Id. at 315.

SUG's total common equity of $1,975,806,000 as of December 31, 2007, includes $89,227,000 representing goodwill at the end of the test year (Exh. AG 1-2, Att. (D)(5) at F-3, F-4).[118] We find that the removal of goodwill from SUG's capitalization will not result in a significant disparity between SUG's rate base and capitalization. In addition, we are not persuaded that such a removal of goodwill will materially alter SUG's capital structure or result in higher rates borne by NEGC's ratepayers.

Also included in SUG's total amount of common equity as of December 31, 2007, are $15,148,000, representing allowances for deferred compensation plans and a negative $11,594,000 representing allowances for accumulated other comprehensive loss (id., Att. (D)(5) at F-4). These items represent balance sheet entries that do not constitute a source of capital to the Company. As such, the Department excludes such amounts from the calculation of capital structure. See Western Massachusetts Electric Company, D.T.E. 05-9, at 13 (2005); Southern Union Company, D.T.E. 04-41, at 13 (2004). Therefore, consistent

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[117] At the end of the test year in that case, Boston Gas Company's capital structure consisted of 14.50 percent long-term debt, 0.96 percent preferred stock, 39.65 percent common equity, and the remaining 44.89 percent of capitalization representing acquisition debts that Keyspan incurred when it purchased Eastern Enterprises. D.T.E. 03-40, at 314. The removal of goodwill from capitalization, including other adjustments, would have resulted in a capital structure consisting of 32.01 percent debt, 1.88 percent preferred stock, and 66.11 percent common equity.

[118] The indicated amount of goodwill relates solely to SUG's distribution operations and is net of impairment losses and write-off (Exh. AG 1-2, Att. (D)(5) at F-21).

with Department precedent, the Department will remove these balance sheet amounts from the common equity capitalization.

Based on the foregoing three adjustments, the resulting total common equity for SUG is $1,883,025,000.[119] These adjustments result in SUG's actual adjusted capital structure for the year ending December 31, 2007, consisting of 61.64 percent long-term debt, 4.17 percent preferred stock, and 34.19 percent common equity.

We acknowledge that this capitalization ratio is somewhat skewed in favor of debt. In imputing a capital structure with minor adjustments to SUG's actual capital structure, however, the Department has attempted to implement two objectives. First, to relieve ratepayers by approximating fiscal policies that management should have been previously implementing in order to take advantage of lower-cost financing, and, second, to provide management with an incentive to introduce greater leveraging in their companies' capital structures. Assabet Water Company, DPU 95-35, at 33 (1996); Ashfield Water Company, D.P.U. 1438/1595, at 5-6 (1984); D.P.U. 1360, at 26; Blackstone Gas Company, D.P.U. 19830/19980, at 26 (1979). In this case, however, SUG has taken advantage of the debt markets and leveraged its investment through long-term borrowings. While the Department has cautioned SUG about excessive reliance on the debt markets, we do not consider its actual capital structure to deviate substantially from sound and well-established utility practice to such a degree that warrants imputation of a hypothetical capital structure. Moreover, although SUG's debt ratio may not

119 The adjusted total common equity of $1,883,025,000 is equal to $1,975,806,000 - $89,227,000 - $15,148,000 - (-$11,594,000).

be consistent with optimum gas distribution utility practice, that fact alone does not warrant the imputation of a hypothetical capital structure. D.P.U. 91-106/138, at 97.[120] To the extent that investors may no longer associate SUG as a gas distribution company, this distinction is more appropriately considered in the context of the appropriate return on equity associated with the Company, not through imputation of a hypothetical capital structure.

Based on the foregoing analysis, the Department rejects the Company's proposed hypothetical capital structure. We direct the Company to use the actual capital structure of SUG as of December 31, 2007, with the adjustments described above. Consistent with these findings, we direct the Company to apply a cost of long-term debt of 6.46 percent and a cost of preferred stock of 7.76 percent. The resulting capital structure is provided in Schedule 5 of this Order.

D. Rate of Return on Common Equity Cost Models

1. Introduction

In determining the proposed 11.60 percent rate of return on common equity,[121] the Company initially applied four cost of common equity models, consisting of the discounted

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[120] See, also, Fall River Gas Company, D.P.U. 18416, at 11-12 (1976) where the Department allowed a 64 percent debt ratio.

[121] As noted previously, the Department found that the Company was not eligible to submit a decoupling proposal at this time. New England Gas Company, D.P.U. 08-35, Interlocutory Order on Scope of Proceeding and Request of the Attorney General and New England Gas Company to Bifurcate at 6 (2008). To maintain consistency with the revenue requirement schedules provided in the Company's initial filing, the Department has retained for presentation purposes the proposed 11.40 percent return on equity in Schedules 1 through 10 attached to this Order.

cash flow ("DCF") model, the risk premium model ("RPM"), the capital asset pricing model ("CAPM"), and the comparable earnings model ("CEM") and arrived at an 11.00 percent rate of return on common equity (Exhs. NEGC-FJH at 6, 63; NEGC-FJH-1, Sch. 1, at 2; Tr. 3, at 380). The Company then made a 0.40 percent upward adjustment to account for what NEGC claimed as the greater business risk attributable to its small size compared to the average size of the gas distribution companies in the comparison group described above (Exhs. NEGC-FJH at 3, 6, 12; NEGC-FJH-1, Sch. 1, at 2). Finally, NEGC added 0.20 percent to compensation for the lack of a decoupling mechanism, as explained above (Exhs. NEGC-FJH at 3, 6, 13; NEGC-FJH-1, Sch. 1, at 2).

The DCF, RPM, CAPM, and CEM are market-based models based on the efficient market hypothesis, which assumes that security prices reflect all relevant information and that prices adjust instantaneously to the arrival of new information (Exh. NEGC-FJH at 23, 25; Tr. 3, 327-328).[122]

The Company determined common equity cost rates of 9.77 percent, 11.39 percent, 10.86 percent, and 17.22 percent based on the DCF, RPM, CAPM, and CEM, respectively (Exhs. NEGC-FJH at 3, 63-64; NEGC-FJH-1, Sch. 1, at 2). Based on these results, the Company determined an 11.00 percent base cost of equity prior to the two proposed upward adjustments described above (Exhs. NEGC-FJH at 3, 63-64; NEGC-FJH-1, Sch. 1, at 2).

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122 The Company asserts that there is support in the academic and financial literature for the need to rely on multiple cost of common equity models in arriving at a recommended common equity cost rate (Company Brief at 107, citing Exh. NEGC-FJH at 26-28).

The Attorney General recommends that the Department reject the Company's proposed rate of return on common equity; instead she proposes an 8.58 percent rate of return on common equity after adjusting for Company size (Attorney General Reply Brief at 36, citing Attorney General Brief at 48-52, 56-57).

2. Discounted Cash Flow

a. Description

The theory behind the DCF model suggests that an investor buys a stock for an expected total return rate to be derived from cash flows, in the form of dividends, and from the appreciation in the market price of the stock (Exh. NEGC-FJH at 28). The sum of the expected rate of return from dividends, or the dividend yield, and the expected growth rate, or appreciation in the market price of stock, is equal to the total return rate expected by investors (id. at 28-29). In this case, NEGC utilized the Gordon model (id. at 36-37). The Gordon model is expressed as: $k = D/P + g$, where k is the investor's required return on common equity, D is the dividend per share paid in the next period, P is the current market price per share of the common stock, D/P is the expected dividend yield, and g is the investor's mean expected long-run growth rate in dividend per share. See, e.g., D.P.U. 07-71, at 125.

In applying the DCF model, the Company first estimated the dividend yield for each company in the comparison group using the average of the spot market prices on May 19, 2008, and the averages of the high and low market prices for the months of March and April 2008 (Exhs. NEGC-FJH at 36; NEGC-FJH-1, Sch. 9). Then the Company took the average for the dividend yields of the nine companies in the comparison group to arrive at a 4.07 percent dividend yield (Exhs. NEGC-FJH at 36; NEGC-FJH-1, Sch. 9).

Next the Company estimated the growth rate of each of the companies in the comparison group, using the average of Value Line's projected long-term earnings per share growth rate and Reuters/Market Guide mean consensus long-term earnings per share growth rate, and took their average giving in a 5.08 percent growth rate (Exhs. NEGC-FJH at 38; NEGC-FJH-1, Sch. 11). Then the Company calculated an adjusted dividend yield of 4.17 percent, that reflect a portion of the estimated growth rate, added this to the 5.08 percent growth rate resulting in a 9.25 percent DCF-determined cost rate of common equity (Exhs. NEGC-FJH at 33-39; NEGC-FJH-1, Sch. 8).

The Company, however, did not use this 9.25 percent rate. Instead, NEGC eliminated five companies with cost rates that are less than or equal to 9.50 percent and used the average rate of the remaining four companies in the comparison group which is equal to 9.77 percent (Exhs. NEGC-FJH at 38-39; NEGC-FJH-1, Sch. 8; Tr. 3, at 390).[123] The Company reasoned that the lowest rate of return on common equity granted to a natural gas distribution company during the year ended March 31, 2008 was 9.10 percent, and the next lowest was 9.50 percent

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123 The five companies in the comparison group that were eliminated, along with their corresponding DCF-calculated common equity cost rates, are: AGL Resources Inc., at 9.23 percent; The Laclede Group, Inc., at 7.61; Piedmont Natural Gas Company, Inc., at 9.11 percent; Southwest Gas Corporation at 9.38 percent; and WGL Holdings, Inc., at 8.88 percent (Exh. NEGC-FJH-1, Sch. 8, at 1). The remaining four companies with their DCF-determined cost rate of equity are: Atmos Energy Corporation at 9.52 percent; NICOR Inc., at 9.59 percent; Northwest Natural Gas Company at 9.65 percent; and South Jersey Industries, Inc., at 10.30 percent (id., Sch. 8, at 1).

(Exhs. NEGC-FJH at 39; NEGC-FJH-1, Sch. 16). On this basis, the Company concluded that it is not reasonable to assume that a common equity cost rate lower than 9.50 percent is realistic and, therefore, NEGC eliminated those five companies (Exh. NEGC-FJH at 39).

b. Positions of the Parties

i. Attorney General

The Attorney General accepts the Company's dividend yield estimate noting that it is close to the six-month average dividend yield for the comparison group (Attorney General Brief at 50). The Attorney General observes that although the Company used only the earnings per share forecast for the comparison group and, thus, ignored all other factors that can be used in estimating the expected DCF growth rate, this earning per share forecast is similar to the forecast growth in gross domestic product of 5.06 percent (id. citing Exhs. NEGC-FJH-1, Schs. 11, at 1, 12, at 7; AG 7-23)). The Attorney General suggests that the Department accepts the 5.08 percent growth rate calculated by the Company (id. at 50-51).

The Attorney General, however, disagrees with the Company's elimination of five companies in the comparison group (id. at 51). The Attorney General recommends that the Department reject this attempt to bias the DCF results upward and instead rely on the DCF analysis for the entire comparison group (id. at 51-52; Attorney General Reply Brief at 34). Accordingly, the Attorney General recommends that the DCF cost rate of equity should be equal to 9.25 percent calculated by the Company as shown in Exhibit NEGC-FJH-1, Schedule 8, at 1, column 5 (Attorney General Brief at 51-52).

In support of her recommendation, the Attorney General claims that the Company misstates the evidence relating to an observation by the Regulatory Research Institute ("RRA") that an allowed return below 9.5 percent is "negative from an investor view point" (Attorney General Reply Brief at 33, citing Company Brief at 110). The Attorney General explains that such a statement is derived from one reporter, RRA, not from a group or all investment analysts (id. at 33, citing Exhs. NEGC-FJH at 39; NEGC-FJH-1, Sch. 16, at 3-7). Also, the Attorney General claims that RRA's observation is taken from a statement that refers to the entire order issued by the New York Public Service Commission regarding the rate case and not simply relating to the cost of common equity (id. at 33-34, citing Exh. NEGC-FJH-1, Sch. 16, at 3).

ii. Company

NEGC asserts it relied on the constant growth form of the DCF model because it is most widely used in public utility regulation where most utilities are in mature state and not transitioning from one phase of growth to another (Company Brief at 108, citing Exh. NEGC-FJH at 35). The Company argues that a return on equity below 9.5 percent is unreasonable and should not be taken into consideration when developing a rate of return on equity based on the DCF model (id. at 110, citing Exh. NEGC-FJH at 39).

The Company claims that an analyst's observation that a low rate of return granted as "negative from an investor view point" is relevant in setting rates, noting that the Department in its recent decisions has not ordered a rate of return on equity for a gas utility that is below ten percent (id. citing D.P.U. 07-71, at 139; D.T.E. 05-27, at 302; D.T.E. 03-40, at 364;

D.T.E. 01-56, at 118; Company Reply Brief at 24). Noting that the lowest allowed rate of return on common equity to an LDC during the year ended March 31, 2008, was 9.10 percent, with the next lowest awarded rate of return on equity being 9.50 percent, NEGC further contends that the average authorized rate of return on equity in litigated cases during the twelve month period ended March 31, 2008, was 10.33 percent relative to an average common equity ratio of 52.42 percent (Company Reply Brief at 24, citing Exh. NEGC-FJH at 39, 64).

Regarding the New York Public Service Commission decision which was observed to be "negative from an investor view point," the Company argues that it is common sense that investors focus on the return on common equity allowed because it is the most influential factor in determining what investors get in return for their investment (id. at 24-25).[124] The Company claims that while there may be other aspects of the New York Public Service Commission decision that were negative to investors, a low return on equity would be most likely to draw the focus of an investor (id. at 25). The Company adds that investors' view is essential in determining how to set the rate of return on equity because utilities compete to attract capital from investors (id.). NEGC further contends that the Attorney General did not present expert testimony to oppose an upward adjustment in the DCF cost rate (Company Brief at 110).

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[124] NEGC cited an evaluation in which the RRA stated the 9.10 percent rate of return on equity granted by the New York Public Service Commission to National Fuel Gas Distribution, a subsidiary of National Fuel Gas Corporation, was "negative from investor viewpoint," well below the average returns authorized nationwide during the past 12 months, and equal to the 9.10 percent granted to Orange & Rockland Utilities in October 2007, which at that time RRA noted to be "the lowest equity return authorized an energy utility nationwide in at least the last 30 years" (Company Brief at 109, citing Exh. NEGC-FJH at 39; see also NEGC-FJH-1, Sch. 16, at 3; Tr. 3, at 387-388; RR-DPU-6).

c. Analysis and Findings

Regarding the Company's adjustment to the dividend yield based on the estimated growth rate, the Department has found that any such growth-related adjustment is inappropriate because the growth rate component of the DCF model is meant to account for growth and that further adjustments would double-count the effect of this growth feature. See D.P.U. 90-121, at 178-179; D.P.U. 88-135/151, at 125-126; D.P.U. 88-67 (Phase I) at 192.

Regarding the Company's estimate of the growth rate based only on earnings per share growth rate, the Department must evaluate such an approach based on its precedent which requires a balanced examination of a variety of growth rate factors. See D.T.E. 99-118, at 83; D.T.E. 98-51, at 120. More specifically, the Department has stated that a variety of quantitative factors, including growth rates in retained earnings, earnings per share, and dividends per share should be examined, but that the final growth rate selection should take into account qualitative factors as well. See D.P.U. 90-121, at 179-180; D.P.U. 88-135/151, at 125.

In eliminating five out of the nine companies in the comparison group with DCF-determined cost rates that are equal to, or less than 9.50 percent, NEGC applied a qualitative rather than quantitative approach to determining its DCF common equity cost rate. This subjectivity tends to create an upward bias in the results of the DCF analysis. Therefore, we will not accept this selective application of the DCF approach on a subset of companies in the comparison group.

In addition, the Department notes that the Company used a version of the DCF model where the growth rate is assumed to be constant. The Department is not persuaded by the validity of this assumption that underlies the Gordon model. Accordingly, we will consider these limitations of the DCF analysis in determining the Company's appropriate rate of return on capital.

3. Risk Premium Model

a. Description

The RPM postulates that the cost of common equity capital is equal to the cost of long-term debt plus a risk premium to compensate for the added risk of being common shareholders (Exh. NEGC-FJH at 40). To arrive at the prospective cost of common equity capital, NEGC relied on the 5.63 percent average consensus forecast of about 50 economists on the expected yield on Moody's Aaa rated corporate bonds for six calendar quarters ending in the third quarter of 2009 as published in the May 1, 2008 Blue Chip Financial Forecasts (id. at 42; Exh. NEGC-FJH-1, Sch. 12, at 6 n.4, at 7).

Then, the Company performed two sets of adjustments on this computed average of quarterly forecasts. First, the Company made a 0.72 percent upward adjustment to reflect the yield spread between Aaa rated corporate bonds and A rated public utility bonds (Exh. NEGC-FJH-1, Sch. 12, at 1, 4). Because the average rating of the comparison group is A3, instead of A, the Company made a second adjustment to recognize the relative risk differential and added an additional yield spread of 0.17 percent (id., Sch. 12, at 1 & n.3).

Adding these two adjustments to the 5.63 percent average Aaa rated corporate bond yield results in an adjusted prospective bond yield of 6.52 percent (id., Sch. 12, at 1).

Next, the Company determined an equity risk premium of 4.87 percent, which is equal to the average of two risk premia, 5.39 percent and 4.34 percent, based on two different studies using historical risk premium calculations (id., Sch. 12, at 1, 5). The first risk premium of 5.39 percent was calculated to be equal to the arithmetic mean total return rate on the S&P's Composite Index from 1926 to 2006 (12.30 percent) minus the arithmetic mean yield on Aaa and Aa corporate bonds for the period 1926 to 2006 (6.10 percent) and the result multiplied by the average adjusted Value Line beta (0.87) of the comparison group of nine companies (id., Sch. 12, at 6, 9; Tr. 3, at 384).

The second risk premium of 4.34 is based on a 2007 study of AUS Consultants on S&P's Public Utility Index and Moody's Public Utility Bond Average Annual Yields, from 1928 to 2006 (Exh. NEGC-FJH-1, Sch. 12, at 8). This risk premium was calculated to be equal to the arithmetic mean holding period returns on S&P Public Utility Index for the period from 1928 to 2006 (11.11 percent) minus the arithmetic mean yield on A rated public utility bonds (6.60 percent) and the result reduced by 0.17 percent to reflect the comparison group's average Moody's bond rating of A3 (id., Sch. 12, at 8 & n.3; Exh. DPU 4-45).

Finally, the Company added the 6.52 percent bond yield to the estimated 4.87 risk premium, which is the average of the 5.39 percent and 4.34 percent risk premia described above, and arrived at an 11.39 percent rate of return on common equity based on the RPM (Exh. NEGC-FJH-1, Sch. 12, at 1).

b. Positions of the Parties

i. Attorney General

Regarding the RPM analysis, the Attorney General claims that the Department has reviewed and rejected this method before (Attorney General Brief at 55-56, citing D.T.E. 03-40, at 359; D.P.U. 96-50, at 128; D.P.U. 95-40, at 97; D.P.U. 93-60, at 261; D.P.U. 92-111, at 265-266; D.P.U. 92-210, at 138-139; D.P.U. 90-121, at 171). The Attorney General claims that the Department has found that the RPM overstates the amount of company-specific risk and overstates the cost of equity (id. at 56). The Attorney General concludes that because the Company has not provided new analyses or new argument, the Department should reject the RPM analysis (id.; Attorney General Reply Brief at 34-35).

ii. Company

The Company notes that the RPM is based upon the efficient market hypothesis and is market-based (Company Brief at 113; Company Reply Brief at 26, citing Exh. NEGC-FJH at 23).[125] The Company claims that although the results of the RPM may be questioned, the academic and financial literature recognize that other models, such as the DCF, have flaws as well (Company Brief at 113, citing Exh. NEGC-FJH at 26-28; Company Reply Brief at 26). The Company claims that the Department has not consistently rejected the RPM but treated it

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125 The Company also made calculations of risk premia based on both historical and projected values and arrived at an RPM-determined rate of return on common equity equal to 12.36 percent (Exh. NEGC-FJH-1, Sch. 12, at 1, 5-6; Tr. 3, at 381-384). The Company, however, asserts that to be conservative it did not rely on this result, reasoning that such a projected market risk premium would not be representative over the future (Company Brief at 113, citing Exh. NEGC-FJH at 48).

as a supplemental approach to the DCF (Company Brief at 113-114, citing D.P.U. 07-71, at 137; Company Reply Brief at 26). The Company suggests that the Department should at least supplement its determination of the Company's rate of return on equity with the results of the RPM analysis (Company Brief at 114; Company Reply Brief at 26).

c. Analysis and Findings

The Department has repeatedly found that a risk premium analysis could overstate the amount of company-specific risk and, therefore, overstate the cost of equity. See D.P.U. 90-121, at 171; D.P.U. 88-135/151, at 123-125; D.P.U. 88-67 (Phase I) at 182-184. More specifically, the Department has found that the return on long-term corporate or public utility bonds may have risks that could be further diversified with the addition of common stocks in investors' portfolios and, therefore, overstates the risk accounted for in the resulting cost of equity. D.P.U. 88-67 (Phase I) at 182-183; D.P.U. 90-121, at 171.

Regarding the Company's downward adjustment to the risk premium using the average adjusted beta for the nine companies in the comparison group, the Department notes that this adjustment could be problematic because the beta is a CAPM-determined measure of risk. As the Company indicated, the RPM and CAPM are similar but two different model formulations used to determine the cost of common equity (Exhs. NEGC-FJH at 41; DPU 4-42). By introducing the beta in estimating the RPM-determined market risk premium, the Company introduced into its analysis an added concern relating to the unrealistic assumptions that underlie the CAPM as described infra.

In addition, the Department notes that the Company used the results of two studies as bases for determining the average rates of returns from which the average yields of long-term bonds were subtracted to determine two alternative market risk premia.[126] The companies included in those studies have investment risks different from utility companies and, therefore, could overstate the resulting rate of return on equity. See D.T.E. 99-118, at 87, citing D.P.U. 906, at 103. Accordingly, the Department finds that the Company's RPM analysis does not accurately measure the required return on common equity for NEGC.

4. Capital Asset Pricing Model

a. Description

The CAPM defines risk as the covariability of a security's return with the market's return, where such covariability is measured by the systematic risk or beta ("β"), the risk which can not be eliminated through portfolio diversification (Exh. NEGC-FJH at 50). The CAPM presumes that investors require compensation for this risk that could not be eliminated through diversification (id. at 50-51). Accordingly, the CAPM postulates that the return to a security is equal to a risk-free rate plus the market risk premium multiplied by the beta of that

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126 From the first study, the Company used the arithmetic mean total return rate of 12.30 percent on the S&P's 500 Composite Index from 1928 to 2006 based on Stocks Bonds Bills and Inflation - Market Results for 1926-2007 - 2008 Yearbook, Morningstar, Inc., 2008 Chicago, IL (Exh. NEGC-FJH-1, Sch. 12, at 6 n.1). From the second study, the Company used the arithmetic mean holding period rate of return of 11.11 percent for S&P's Public Utility Index from 1928-2006 based on S&P Public Utility Index and Moody's Public Utility Bond Average Annual Yields, 1928-2006, AUS Consultants, 2007 (id., Sch. 12, at 6 n.1; Exh. DPU 4-41, Att.).

security to reflect the systematic risk of that security relative to the market (id. at 51).[127] A security with a beta less than 1.0 indicates that it has lower return variability than that of the market; a beta greater than 1.0 indicates greater return variability than that of the market (id. at 50).

In addition to the traditional CAPM, the Company also used an empirical CAPM ("ECAPM") that is intended to refine and expand the traditional CAPM (id. at 52; Exh. DPU 4-18, Att. at 189; Tr. 3, at 398-401). The Company indicated that, consistent with the observed return-risk relationship, the ECAPM typically produces a return-risk relationship that is flatter than what the traditional CAPM predicts (Exhs. NEGC-FJH at 51-52; DPU 4-18, Att. at 189).[128] Based on the results of an empirical study, the Company used a specific formulation of the ECAPM (Exhs. NEGC-FJH at 52).[129]

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127 The traditional CAPM is a linear relationship expressed as $R_s = R_f + \beta(MRP)$, where R_s is the return rate on the common stock, R_f is the risk-free rate of return, and MRP is the market risk premium equal to $(R_m - R_f)$, where R_m is the market rate of return (Exh. NEGC-FJH at 51). The line traced by this return-risk relationship, with the intercept equal to R_f, is also referred to as the security market line (id.).

128 The general formulation of the ECAPM is the linear relationship: $R_s = R_f + \alpha + \beta(MRP - \alpha)$, where α is a fraction to be determined empirically (Exhs. NEGC-FJH at 52 n. 16; DPU 4-18, Att. at 189; Tr. 3 at 397-399). It is noted that "[a]ll the potential vagaries of the traditional CAPM are telescoped into the constant α . . . " (Exh. DPU 4-18, Att. at 189; Tr. 3 at 399).

129 The specific ECAPM equation used by the Company is given by the expression: $R_s = R_f + .25\ (R_m - R_f) + .75\beta(R_m - R_f)$ (Exhs. NEGC-FJH at 52; DPU 4-18, Att. at 190). This relationship is an approximation based on a study that estimated α at 2.0 percent (Exhs. NEGC-FJH at 52 n.16; DPU 4-18, Att. at 190; Tr. 3, at 398, 407). Seven other empirical studies show different estimates for α, including a value equal to 4.6 percent, and ranges of values from 1.63 percent to 5.04 percent, 5.32 percent to

(continued...)

In applying the CAPM and ECAPM, the Company first determined the risk-free rate to be equal to 4.58 percent (id. at 53). The Company stated that this rate is based on the average consensus forecast of the reporting economists in the May 2008 issue of Blue Chip Financial Forecasts for the yields on 30-year U.S. Treasury Notes for the six quarters ending in the third quarter of 2009 (id. at 53, 1; Exh. NEGC-FJH-1, Sch. 14, at 4).

Next, the Company estimated a market risk premium of 7.10 percent determined to be equal to the 12.30 percent Morningstar, Inc., mean long-term historical total return minus the 5.20 percent historical return rate on long term U.S. Government Securities (Exh. NEGC-FJH at 55-56). Then, the Company applied this 7.10 percent market risk premium on both the CAPM and the ECAPM to determine the common equity cost rate for each of the nine comparison groups of companies (Exh. NEGC-FJH-1, Sch. 14, at 3). The average common equity cost rates for the nine companies in the comparison group are 10.74 percent and 10.97 percent based on the CAPM and ECAPM, respectively, giving an average for the two models equal to 10.86 percent (id., Sch. 14, at 1, 3).[130]

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129 (…continued) 8.17 percent, 10.08 percent to 13.55 percent, 4.08 percent to 9.36 percent, -9.61 percent to 12.24 percent, and -3.6 percent to 3.6 percent (Exh. DPU 4-18, Att. at 190; Tr. 3, at 407-408).

130 The Company initially determined two alternative estimates of the market risk premium, which are 11.71 percent and 7.10 percent (Exh. NEGC-FJH at 55-56). The first estimate was based on projected data, the second on historical data (id.). The Company used the average of these two premia (9.41 percent) and applied it to both the CAPM and the ECAPM to determine the common equity cost rate for each of the nine companies in the comparison group. The results were an average common equity cost rate of 12.74 percent based on the CAPM and 13.05 percent based on the ECAPM for (continued…)

b. Positions of the Parties

i. Attorney General

The Attorney General claims that many of the underlying assumptions of the CAPM do not apply in the case of investment in the stocks of the comparison group of companies (Attorney General Brief at 52-53). The Attorney General claims that the Department has found the assumptions underlying the CAPM to be too restrictive to make useful the application of the CAPM to a utility stock (id. at 53, citing D.T.E. 03-40, at 360; D.T.E. 96-50, at 125; D.P.U. 92-210, at 148-150; D.T.E. 92-78, at 113; D.T.E. 88-67 (Phase I) at 184; D.P.U. 956, at 54-55. The Attorney General claims that the Company's analysis did not address the problems associated with these assumptions and, therefore, the Department should reject the use of the CAPM analysis as a method for determining the cost of equity (id. at 54; Attorney General Reply Brief at 34-35).

ii. Company

The Company disagrees with the Attorney General's suggestion that the Department should reject the use of the CAPM because it has been rejected in the past and that the underlying assumptions of the model are unrealistic (Company Brief at 116). Noting that the CAPM is based on the efficient market hypothesis and is market-based, the Company argues

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130 (…continued)
an average of the two models equal to 12.89 percent (id.; Exh. NEGC-FJH-1, Sch. 14, at 1-2). The Company, however, concluded that it is not realistic to rely on the projected market risk premium and, therefore, used only the result based on the historical market risk premium of 7.10 percent (Exhs. NEGC-FJH at 56; NEGC-FJH-1, Sch. 1, at 2, Sch. 14, at 1; RR-DPU-7 (Rev.)).

that although some of CAPM assumptions may be questioned, the academic and financial literature recognize that other models, such as the DCF, have flaws as well (id. citing Exh. NEGC-FJH at 26-28; Company Reply Brief at 25-26, citing Exh. NEGC-FJH at 23, 26-28).

The Company claims that the Department has placed "limited weight" on the results of the CAPM and, therefore, has not consistently rejected the CAPM (id. citing D.T.E. 01-56, at 113; Company Reply Brief at 26). The Company suggests that the Department should at least give some weight to the CAPM in setting the Company's rate return on common equity (Company Brief at 116; Company Reply Brief at 26).

c. Analysis and Findings

The Department has rejected the use of the traditional CAPM as a basis for determining a utility's cost of equity because of a number of limitations, including questionable assumptions that underlie the model.[131] D.P.U. 956, at 54; D.T.E. 03-40, at 359-360.

The ECAPM is intended to adjust the traditional CAPM in order to provide a better model fit and explanation of the empirical test results. The Company applied a specific value

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131 The assumptions underlying the CAPM model are: (1) capital markets are perfect with no transaction costs, taxes, or impediments to trading, all assets are perfectly marketable, and no one trader is significant enough to influence price; (2) there are no restrictions to short-selling securities; (3) investors can lend or borrow funds at the risk-free rate; (4) investors have homogeneous expectations (i.e., investors possess similar beliefs on the expected returns and risks of securities); (5) investors construct portfolios on the basis of the expected return and variance of return only, implying that security returns are normally distributed; and (6) investors maximize the expected utility of the terminal value of their investment at the end of one period (Exh. DPU 4-42, Att at 170, Appendix 5-A, Capital Asset Pricing Model; see D.P.U. 956, at 54 & n.36).

for α, which is equal to 2.00 percent, based on a 1989 study. The record, however, shows that there are at least seven other studies with different estimated values of the factor α, ranging from -9.61 percent to 13.56 percent (Exhs. NEGC-FJH at 52; DPU 4-18, at 190; DPU 4-18, Att.; Tr. 3, at 398). As the Company acknowledged, one can develop other formulations of the ECAPM based on these other studies in addition to the specific ECAPM formula used by the Company (Tr. 3, at 408). Based on the above considerations, the Department finds that the traditional CAPM and the ECAPM would have limited value in determining the Company's rate of return on common equity in this case.

5. Comparable Earnings Model

a. Description

The CEM is based on the economic concept of opportunity cost, where the opportunity cost of a capital invested in a utility's common stock is what that capital would yield in an alternative investment of similar risk (Exh. NEGC-FJH at 57). The Company used a CEM comparison group of companies that excludes regulated distribution companies to avoid circularity,[132] noting that rates of returns on regulated distribution companies are influenced by regulatory rate determinations (id. at 56, 59).

The Company included in the CEM comparison group a total of 17 domestic non-price regulated companies, with risks comparable to those of the nine companies in the comparison group, using the betas and their standard errors of regressions taken from Value Line's weekly

[132] In performing the CEM analysis, the Company's witness stated that he applied a method that he personally developed (Exhs. NEGC-FJH at 59 and App. A at 5; DPU 4-16; Tr. 3, at 344-346, 370-371).

market prices over the most recent 260 weeks (five years) of data (id. at 59-61; Tr. 3, at 344-346).[133] The average five-year projected rate of return for the 16 of the 17 companies in the CEM comparison group is 17.22 percent (Exh. NEGC-FJH-1, Sch. 15, at 1).[134]

The Company stated that because this 17.22 percent cost rate is so different from the cost rates derived from the applications of the other three cost of common equity models, it gave no consideration to this result in arriving at the 11.0 percent base cost of common equity, prior to the two upward adjustments noted above and further discussed below (Exhs. NEGC-FJH at 62; NEGC-FJH-1, Sch. 1, at 2-3; Tr. 3, at 350-351).

b. Positions of the Parties

i. Attorney General

The Attorney General states that the Department has repeatedly rejected in the past the application of the CEM (Attorney General Brief at 55, citing D.T.E. 03-40, at 360-361; D.P.U. 96-50, at 131-132; D.P.U. 92-250, at 160-161; D.P.U. 92-111, at 280-281; D.P.U. 92-210, at 155; D.P.U. 905, at 48-49. The Attorney General claims that the Department has rejected this method as unreliable because the earned return on common equity did not necessarily equal the companies' cost of capital (id. citing D.P.U. 905, at 48-49, citing

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133 The Company indicated that the average adjusted and unadjusted betas for the 17 non-price regulated CEM comparison group of companies are 0.89 and 0.76, respectively, compared to the 0.87 and 0.76 average adjusted and unadjusted betas, respectively, for the nine companies in the comparison group (Exh. NEGC-FJH-1, Sch. 15, at 1).

134 One company, Northrop Grumman, was removed as a statistical outlier because of its relatively high five-year projected rate of return of 89.00 percent (Exhs. NEGC-FJH at 61, NEGC-FJH-1, Sch. 15, at 1).

Boston Gas Company, D.P.U. 1991, at 56 (1979)). The Attorney General concludes that because the Company did not provide any reason to change such a precedent, the Department should reject the Company's CEM analysis (id.; Attorney General Reply Brief at 34-35).

ii. Company

The Company explains the steps it followed in applying the CEM (Company Brief at 116-118). NEGC, however, gave no consideration to the CEM result in arriving at its recommended rate of return on common equity, noting that the CEM cost rate is so different from the cost rates derived from the applications of the other three cost of equity models (id. at 118).

c. Analysis and Findings

The Department has generally rejected the results of the CEM analysis because the risk criteria provided were not sufficient to establish the comparability of the non-regulated group of firms with the distribution company being considered. D.T.E. 01-56, at 116. Although the average adjusted and unadjusted betas of the CEM comparison group of 17 non-price regulated companies are comparable with the average adjusted and adjusted betas of the nine comparison group of companies, there are other risk criteria that must be evaluated as the basis for selecting an appropriate CEM comparison group of companies. D.T.E. 01-56, at 116.

In addition, the Department has found that the use of the beta as a criterion in selecting a comparable group of companies is not a reliable investment risk indicator given its statistical measurement limitations. D.P.U. 96-50 (Phase I) at 132. Moreover, the beta, which is a measure of risk based on the CAPM, reflects the limitations of that model, including its unrealistic assumptions as noted above. The results of the CEM analysis here, which the Company decided not to use in its determination of the recommended cost of equity, reflect these concerns. Accordingly, the Department will not rely on the results of the CEM analysis as a basis for determining the rate of return on common equity for NEGC.

E. Proposed Adjustment For Company Size

1. Description

The Company proposed to add 0.40 percent or 40 basis points to the 11.00 percent base cost of common equity derived from the applications of its equity cost models to account for an additional business risk attributable to the Company's small size compared to the average size of the nine companies included in the comparison group (Exh. NEGC-FJH at 12-13, NEGC-FJH-1, Sch. 1, at 2). The Company's adjustment was based on a study performed by Morningstar, Inc. (formerly Ibbotson SBBI) (Exhs. NEGC-FJH at 11; NEGC-FJH-1, at 7-19; Tr. 3, at 416) ("Morningstar study"). That study included all companies listed in the NYSE/AMEX/NASDAQ exchanges with data going back to 1926 (Exh. NEGC-FJH-1, at 8). The Morningstar study divided these companies into ten according to size as measured by their capitalization, and, as of September 30, 2007 there were a total of 2,416 companies listed, with 1,775 belonging to the tenth decile and the rest falling into the first to the ninth deciles (Exh. NEGC-FJH-1, Sch. 1, at 9).

The Morningstar study used the traditional CAPM as the framework for analysis and found that smaller securities have had returns that are not fully explained by the model (Exh. NEGC-FJH-1, Sch. 1, at 15). More specifically, the return in excess of the riskless rate, predicted by the traditional CAPM, increases as one moves from the largest group of companies in the first decile to the smallest group of companies in the tenth decile (id., Sch. 1, at 15).

For each of the ten groups of companies, the Morningstar study provided the rate of return in excess of the rate of return predicted by the traditional CAPM (id., Sch. 1, at 16; see also Exh. NEGC-FJH-1, Sch. 1, at 4-5, 7-19, citing Stocks, Bonds, Bills, and Inflation - Market Results for 1926-2007 - 2008 Yearbook Valuation Edition, Morningstar, Inc., 2008 Chicago, IL.). The study, which referred to this excess return as the "size premium," showed that the size premium increases as the company size decreases (Exh. NEGC-FJH-1, Sch. 1, at 15).

As its basis for the proposed 0.40 percent adjustment, the Company determined that the average size of the nine companies in the comparison group based on permanent capital is 25.7 times compared to that of the permanent capital of NEGC (id., Sch. 1, at 4). The Company noted that NEGC falls within the last group, or the tenth decile of companies included in the Morningstar study, while the average size of the nine companies in the comparison group falls within the sixth group or sixth decile (id., Sch. 1, at 4). The Company indicated that the size premium for the sixth decile, applicable to the nine comparison group of companies, is 1.60 percent, while the size premium for the tenth decile applicable to NEGC is 5.82 percent (id., Sch. 1, at 4). Based on the difference between these two size risk premia, which is 4.22 percent (5.82 - 1.60), the Company stated that an upward adjustment of 4.22 percent or 422 basis points should be made to the cost rate derived from the comparison group of gas distribution companies (Exh. NEGC-FJH at 12). The Company, however, stated that it only proposed a 0.40 percent or 40 basis point upward adjustment on the 11.00 percent base cost rate of common equity in order to be extremely conservative and yet still provide some recognition of the effect of NEGC's small size in its required cost of common equity (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General opposes the Company's proposed adjustment to increase the cost of equity for NEGC by 40 basis points (Attorney General Brief at 56; Attorney General Reply Brief at 30). The Attorney General claims that the former Fall River and North Attleboro operations are not stand-alone corporations or independent subsidiaries, but instead operating divisions that are financed and managed by SUG (Attorney General Brief at 56, citing Exh. NEGC-FJH-1, Sch. 1, at 4, Sch. 4, at 1; Attorney General Reply Brief at 30).

The Attorney General claims that SUG is larger compared to the average size of the comparison group of companies and that the Department recognized the expected cost and financing benefits when approving SUG's acquisitions of FRG and NAG (Attorney General Brief at 56, citing Exh. NEGC-FJH-1, Sch. 1, at 4, Sch. 4, at 1; Attorney General Reply Brief at 30, citing Exh. NEGC-DLB, at 2, 4).[135]

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[135] The Attorney General states that the average permanent capital of the comparison group of companies is \$1.9 billion compared to that of SUG which is \$5.6 billion (Attorney General Brief at 56, citing Exh. NEGC-FJH-1, Sch. 1, at 4, Sch. 4, at 1). In addition, the Attorney General states that the average market capitalization of the comparison

(continued…)

The Attorney General recommends that, if the Department were to make an adjustment to the cost of equity due to the size of the Company, its cost of common equity should be adjusted downward by 67 basis points to recognize that SUG is significantly larger than the average companies in the comparison group and, therefore, less risky (Attorney General Brief at 56; Attorney General Reply Brief at 32-33).[136] The Attorney General asserts that this proposed adjustment is based on the testimony, exhibits, and data provided by the Company's cost of capital witness who provided a formula for quantifying risk differential (Attorney General Reply Brief at 33, citing Exhs. NEGC-FJH, at 8-12; NEGC-FJH-1, Sch. 1, at 4-5). The Attorney General concludes that using a 9.25 percent cost of equity based on the results of the DCF analysis, the cost of equity for the Company, adjusted for size, should be equal to 8.58 percent (9.25 - 0.67) (Attorney General Brief at 57).

b. Company

The Company argues that an allowance of a return on equity that considers size is consistent with Department precedent, noting that the Department did not reject the adjustment to the rate of return on equity of The Berkshire Gas Company because of its small size and

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135 (…continued)
group of companies is $1.7 billion compared to that of SUG which is $3.9 billion (id. citing Exh. NEGC-FJH-1, Sch. 1, at 4, Sch. 4, at 1).

136 The Attorney General calculated this 67 basis points equal to the difference between SUG's fourth decile size premium of 0.93 percent and the comparison group of companies sixth decile size premium of 1.60 percent (Attorney General Brief at 56-57, citing Exh. NEGC-FJH-1, Sch. 1, at 4).

despite its association with Energy East Corporation (Company Brief at 120, citing D.T.E. 01-56, at 100-101, 111; Company Reply Brief at 19).

NEGC argues that it is a basic premise in finance that risk relates to where capital is invested; NEGC further maintains that because capital is invested in NEGC, not SUG, the cost of capital must be determined on the basis of NEGC's size alone (Company Brief at 101-102, citing Brealey and Myers, Principles of Corporate Finance, at 204-205 (1996); Company Reply Brief at 18-19).

The Company argues that although NEGC is part of SUG, NEGC is a very small company and its earnings are more at risk due to significant events such as the loss of a few large customers (Company Brief at 119-120, citing Exh. NEGC-FJH at 9; Company Reply Brief at 18).[137] The Company criticizes the Attorney General for not explaining how the Company is not riskier because of its small customer base (Company Reply Brief at 18). Regarding the Attorney General's suggestion to reduce by 67 basis points the rate of return of NEGC, the Company states that the Attorney General's argument is not based on expert testimony of any cost of capital witness (Company Brief at 119; Company Reply Brief at 19). The Company asserts that it proposed a 0.40 percent, or 40 basis point, upward adjustment to the 11.00 percent base cost of common equity in order to be extremely conservative, and yet

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137 The Company contends that there is evidence in the financial literature that smaller companies tend to be more risky than larger companies, causing investors to expect greater returns to compensate for the greater risk (Company Brief at 118-119, citing Exh. NEGC-FJH at 8-9; Tr. 3, at 322).

still provide a token recognition of the impact of NEGC's small size on common equity cost rate (Company Brief at 120, citing Exh. NEGC-FJH at 12).

3. Analysis and Findings

The Department has a number of concerns on the Company's proposed upward adjustment on the rate of return on common equity. The Morningstar study includes companies that are non-price regulated such that their risk profiles may not be comparable with the risk profiles of the companies in the comparison group and of NEGC. More specifically, the companies included in the Morningstar study have betas greater than one, unlike the betas of the companies in the comparison group that are less than or at most equal to one.[138] Therefore, using company size only to place the companies of the comparison group within the sixth decile and NEGC within the tenth decile may not provide a sufficient basis for comparability.

In addition, the estimates of the size premia for each of the ten deciles of companies in the Morningstar study were based on the traditional CAPM. As we noted above, there are many limitations of the traditional CAPM including the underlying model assumptions. The calculations of rates of return on common equity, including the calculations of the size premia in the Morningstar study, would reflect those limitations. Based on these considerations, the

138 In the case of the CEM analysis, we note that all the 17 non-regulated companies in the CEM comparison group were chosen to have betas, as the measure of risk, that are less than one in order to be comparable to the betas of the nine gas distribution companies in the comparison group. Yet, the record shows that the resulting rate of return on common equity using the CEM model was too high, such that the Company did not give weight to such a result.

Department concludes that the Company's proposed upward adjustment of 0.40 percent tends to overstate NEGC's cost rate of common equity.

F. Proposed Adjustment for Mitigation of Risk

1. Description

The Company proposes to add 0.20 percent, or 20 basis points, to the base cost of common equity to compensate for the absence of tariff provisions that mitigate the business risks associated with changes in weather and declining average usage per customer (Exhs. NEGC-FJH at 12-13). The Company claimed that unlike NEGC, a majority of companies in the comparison group have tariffs in place that mitigate such risks (id. at 6, 12). More specifically, the Company claimed that approximately 78 percent of the nine companies in the comparison group have some form of revenue decoupling mechanism and 89 percent have some form of weather normalization adjustment ("WNA") clauses and other weather-innovative rate design (or an average of 84 percent) (id., at at 6, 12-13; Exh. NEGC-FJH-1, Sch. 1, at 3 n.7; Sch. 3, at 3, 4).

The Company argues that the full value of such protection from revenue decoupling and weather normalization is 25 basis points on a required common equity cost rate (Exh. NEGC-FJH at 12-13). On this basis, the Company multiplied this 25 basis points by 84 percent and rounded up the result to arrive at the proposed 20 basis points adjustment (id.; Exh. NEGC-FJH-1, Sch. 1, at 3 n.7). No party commented on the Company's proposal.

2. Analysis and Findings

The Department finds that the Company failed to provide adequate analysis and evidence to support its proposed revenue protection adjustment to its base common equity rate. Specifically, we find that the Company has failed to demonstrate that the various rate mechanisms, including weather normalization adjustment tariffs in certain of the comparison group companies, would warrant a 20 basis point increase on common equity cost rate.[139]

G. Conclusion

The standard for determining the allowed rate of return on common equity is set forth in Bluefield and Hope. The allowed return on common equity should preserve the Company's financial integrity, should allow it to attract capital on reasonable terms, and should be comparable to returns on investments of similar risk. See Bluefield at 692-693; Hope at 603.

In support for its calculations of an appropriate rate of return on equity, the Company has presented analyses using the DCF, RPM, CAPM, and CEM applied on the financial data of a comparison group of nine gas distribution companies. The use of these empirical analyses in this context, however, is not an exact science. A number of judgments are required in conducting a model-based rate of return analysis. The Department looks to base its judgement on substantial evidence. Each level of judgment to be made contains the possibility of inherent

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[139] Although the Department requested that NEGC provide copies of the approved tariffs from companies in the comparison groups for the indicated revenue decoupling mechanisms, WNA clauses, and innovative weather rate designs, the Company was unable to provide them (Exhs. DPU 4-28; DPU 4-29; DPU 4-30; RR-DPU-11).

bias and other limitations. D.T.E. 01-56, at 117; Western Massachusetts Electric Company, D.P.U. 18731, at 59 (1977).

The record in this proceeding shows that there is a wide range of results produced by the Company's analyses as well as that of the Attorney General. In the case of the CEM, for example, the Company's cost of capital witness explicitly did not use the results of such an analysis because such results fall outside of the range of reasonable rate of return. Similarly, the RPM and CAPM, with all their limitations including those arising from the underlying model assumptions applied on the financial data of the comparison group of companies, could potentially overstate the Company's risk and rate of return.

Similarly, we note the limitations of the DCF analysis, including the simplifying assumptions that underlie the Gordon Model, and the inherent limitations in comparing the Company to publicly traded companies. We reject the Company's attempt to bias upward the DCF results by selecting only those four companies in the comparison group with DCF-calculated rate of return on equity greater than 9.50 percent and deleting the other five companies with rates of return less than or equal to 9.50 percent. Similarly, we reject the Company's forty basis point adjustment on the rate of return on equity due to the relative size of the Company. Consequently, we reject also the Attorney General's suggestion to adjust the Company's rate of return on equity by 67 basis points on the basis of the size of the Company.

Therefore, while the results of analytical models are useful, the Department must ultimately apply its own judgment to the evidence to determine an appropriate rate of return. We must apply to the record evidence and argument considerable judgment and agency expertise to determine the appropriate use of the empirical results. Our task is not a mechanical or model-driven exercise. D.T.E. 07-71, at 139; D.T.E. 01-56, at 118; D.P.U. 18731, at 59; see also Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 15 (1978).

Based on a review of the evidence presented in this case, the arguments of the parties, and the considerations set forth above, the Department finds that an allowed rate of return on common equity of 10.05 percent is within a reasonable range of rates that will preserve the Company's financial integrity, allow it to attract capital on reasonable terms, will be comparable to earnings of companies of similar risk and, therefore, is appropriate in this case. In making these findings, we have considered both qualitative and quantitative aspects of the Company's various methods for determining its proposed rate of return on equity, as well as the arguments of the parties in this proceeding.

In the Department's determination of an appropriate rate of return on common equity for NEGC, we have considered the downward pressure on the Company's financial risk brought about by the pass-through nature of the Pension/PBOP mechanism, the residential assistance adjustment mechanism ("RAAF"), and the bad debt reconciliation mechanism through the operation of the LDAC. We have also taken the deficiencies in NEGC's customer service as identified in Section V.A. above, into consideration to reduce the appropriate return on equity relating to what we otherwise would have granted. D.T.E. 02-24/25, at 231; D.P.U. 92-250, at 161-162; cf. D.P.U. 92-78, at 115.

VII. RATE STRUCTURE

A. Rate Structure Goals

Rate structure defines the level and pattern of prices charged to each customer class for its use of utility service. The rate structure for each rate class is a function of the cost of serving that rate class and how rates are designed to recover the cost to serve that rate class. The Department has determined that the goals of designing utility rate structures are to achieve efficiency and simplicity, and ensure continuity of rates, fairness between rate classes, and corporate earnings stability. D.T.E. 03-40, at 365; D.T.E. 02-24/25, at 252; D.T.E. 01-56, at 134; D.T.E. 01-50, at 28; D.P.U. 96-50 (Phase I) at 133. Efficiency means that the rate structure should allow a company to recover the cost of providing the service and should provide an accurate basis for consumers' decisions about how to best fulfill their needs. The lowest-cost method of fulfilling consumers' needs should also be the lowest-cost means for society as a whole. Thus, efficiency in rate structure means that it is cost-based and recovers the cost to society of the consumption of resources to produce the utility service. D.T.E. 03-40, at 365-366; D.T.E. 02-24/25, at 252; D.T.E. 01-56, at 135. In practice, meeting the goal of efficiency should involve rate structures that provide strong signals to consumers to decrease excess energy consumption in consideration of price and non-price social, resource, and environmental factors.

The Department has determined that a rate structure achieves the goal of simplicity if it is easily understood by consumers. Rate continuity means that changes to rate structure should be gradual to allow consumers to adjust their consumption patterns in response to a change in structure. Fairness means that no class of consumers should pay more than the costs of serving that class. Earnings stability means that the amount a company earns from its rates should not vary significantly over a period of one or two years. D.T.E. 03-40, at 366; D.T.E. 02-24/25, at 252-253; D.T.E. 01-56, at 135.

There are two steps in determining rate structure: cost allocation and rate design. Cost allocation assigns a portion of the company's total costs to each rate class through an embedded allocated COSS. The COSS represents the cost of serving each class at equalized rates of return given the company's level of total costs. D.T.E. 03-40, at 366; D.T.E. 02-24/25, at 253; D.T.E. 01-56, at 135; D.T.E. 01-50, at 29; D.P.U. 96-50 (Phase I) at 133.

There are four steps to develop a COSS. The first step is to functionalize costs. In this step, costs are associated with the production, transmission, or distribution function of providing service. The second step is to classify expenses in each functional category according to the factors underlying their causation. Thus, the expenses are classified as demand-, energy-, or customer-related. The third step is to identify an allocator that is most appropriate for costs in each classification within each function. The fourth step is to allocate all of a company's costs to each rate class based upon the cost groupings and allocators chosen, and to sum these allocations in order to determine the total costs of serving each rate class. D.T.E. 03-40, at 366-367; D.T.E. 02-24/25, at 253; D.T.E. 01-56, at 136; D.T.E. 98-51, at 131-132; D.P.U. 96-50 (Phase I) at 133-134.

The results of the COSS are compared to the revenues collected from each rate class in the test year. If these amounts are close, then the revenue increase or decrease may be allocated among the rate classes so as to equalize the rates of the return and ensure that each rate class pays the cost of serving it. If, however, the differences between the allocated costs and the test-year revenues are great, then, for reasons of continuity, the revenue increase or decrease may be allocated so as to reduce the difference in rates of return, but not to equalize the rates of return in a single step. D.T.E. 02-24/25, at 253-254; D.T.E. 01-56, at 136; D.T.E. 01-50, at 29.

As the previous discussion indicates, the Department does not determine rates based solely on costs but also explicitly considers the effect of its rate structure decisions on customers' bills and the Department's goals with respect to rate structures. For instance, the pace at which fully cost-based rates are implemented depends, in part, on the effect of the changes on customers. For example, considering the goals of efficiency and fairness, the Department has also ordered the establishment of special rate classes for certain low-income customers and considers the effect of such rates and rate changes on low-income customers. D.T.E. 03-40, at 367; D.T.E. 02-24/25, at 254; D.T.E. 01-56, at 137; D.T.E. 01-50, at 29-30.

In order to reach fair decisions that encourage efficient utility and consumer actions, the Department's rate structure goals must balance the often divergent interests of various customer classes and work to decrease inter-class subsidies unless a clear record exists to support — or statute requires — such subsidies. See, e.g., G.L. c. 164, § 1F(4)(I). The Department reaffirms its rate structure goals that result in rates that are fair and cost-based and enable customers to adjust to changes. D.T.E. 02-24/25, at 254; D.T.E. 01-56, at 137; D.T.E. 01-50, at 30.

The second step in determining the rate structure is rate design. The level of the revenues to be generated by a given rate structure is governed by the cost allocated to each rate class in the cost allocation process. The pattern of prices in the rate structure, which produces the given level of revenues, is a function of the rate design. The rate design for a given rate class is constrained by the requirement that it should produce sufficient revenues to cover the cost of serving the given rate class and, to the extent possible, meet the Department's rate structure goals discussed above. D.T.E. 03-40, at 368; D.T.E. 02-24/25, at 254-255; D.T.E. 01-56, at 136-137; D.T.E. 01-50, at 30. Rate design is particularly important with respect to the goals of achieving efficiency in customer consumption decisions.

B. Cost Allocation

The Company performed an allocated COSS as a basis to assign or allocate costs to customer rate classes (Exh. NEGC-DAH at 9). The COSS identified each item contributing to NEGC's revenue requirement for distribution service only (id. at 12). The COSS excluded gas costs and revenues which are reconciled and collected through the CGAC (id.).

The COSS used a three-step process to allocate costs to the various rate classes. The first step is functionalization, where the plant investment costs and operating expenses were categorized by the operational functions with which they are associated (e.g., gathering, storage, transmission, distribution, and customer service) (id. at 10). The second step is classification where the functional cost elements were classified by the factor of utilization most closely matching cost causation (e.g., customer, demand, and energy) (id.). The final step is the allocation of the functionalized and classified costs to the various rate classes (id. at 11). This allocation is accomplished through direct assignment, the use of external allocation factors, and internal allocation factors (id.).

The COSS used production, storage, and distribution as the three functions in the study (id. at 13). The production function captured the costs related to NEGC's propane facilities (id.). The storage function captured the costs related to the Company's LNG facilities, and the distribution function captured all the remaining costs (id.). Three cost classifications were used in the study: (1) demand; (2) customer; and (3) commodity (id. at 14). NEGC used the sales peak proportional responsibility factor to allocate the production and storage plant costs (id. at 15). The Company stated that because production and storage costs are incurred for peak period service, only peak period throughput was used (id. at 15). Also, because the production and storage facilities are used for the benefit of sales customers only, only sales throughput was used (id.).

According to the Company, its distribution plant was classified as "demand" or "customer," and the demand costs were allocated on the basis of a proportional responsibility factor and the customer costs were allocated on weighted customer basis (id. at 16). Common costs, such as land, rights-of-way, and other equipment, were allocated on internal factors based on the directly-allocated costs (id.). NEGC classified and allocated the intangible plant costs on a customer basis (id. at 17). The general plant costs were classified and allocated on the basis of an internal factor that is based on the classification and allocation of production, storage, and distribution plant costs (id.). Meter costs were allocated to the rate classes on a meter factor developed from data supplied by NEGC for both the Fall River and North Attleboro service areas (id. at 16). Production and storage costs were classified as demand and allocated on the basis of the peak proportionality responsibility factor (id. at 18).

All customer account expenses were classified as customer-related costs (id.). Meter reading costs were allocated based on the amount of time taken to read meters (id. at 18-19). Labor-related administrative and general costs, injuries and damages, and pension and benefits were allocated on the basis of labor (id. at 19). Property insurance costs were allocated on the basis of total plant, while maintenance of general plant and repair expenses were allocated on an internal plant factor (id. at 19-20). Depreciation expenses were allocated based on the related plant and taxes other than income taxes were allocated on a plant or labor basis depending on the type of tax (id. at 20). The remaining rate-base costs were classified and allocated on internal factors, with the exception of customer deposits which were classified as customer costs and allocated on a factor representing the balances by rate class (id. at 18).

According to NEGC, the results of the COSS show that the Company is currently earning an overall return of 2.21 percent, with class returns ranging from negative 11.28 percent for residential non-heating customers (R-1) to 32.93 percent for large high load factor C&I customers (G-53) (id. at 20). The Company also states that residential non-heating (R-1) and residential heating (R-3) customers have class returns below the system average, while all the C&I customers (i.e., G-41, G-42, G-43, G-52, and G-53) show class returns in excess of the system average (id.). No other party commented on the Company's COSS.

The Department has evaluated NEGC's proposed COSS and finds that it is consistent with Department precedent for cost allocation. D.T.E. 01-56, at 138; D.P.U. 96-50 (Phase I) at 136. Thus, the Department accepts NEGC's proposed COSS.

C. Marginal Cost

1. Introduction

The use of a marginal cost of service ("MCS") study in rate making provides consumers with price signals that accurately represent the cost associated with consumption decisions. D.T.E. 03-40, at 372. Rates based on the MCS study will allow consumers to make informed decisions regarding their use of utility service, promoting efficient allocation of societal resources. D.P.U. 07-71, at 159; D.T.E. 03-40, at 372; D.T.E. 02-24/25, at 252.

NEGC's MCS analyzed the increased costs that the Company would incur if it provided an additional unit of service (Exh. NEGC-JDS-2, at 2). The MCS includes the calculation of the following components: (1) marginal cost of capacity-related distribution plant; (2) marginal capacity-related operations expense; (3) marginal capacity-related maintenance expense; (4) marginal general plant costs; (5) marginal administrative and general expense; and (6) marginal materials and supplies cost (id. at 6). The Company used econometric analyses and multi-variate regression analyses to estimate the marginal distribution costs (id. at 3). The Company prepared the MCS based on an analysis of data for the period 1979 to 2007 for the Fall River service area only (id. at 4).

2. Positions of the Parties

NEGC contends that the Company's MCS complies with the Department's directives (Company Brief at 133, citing D.T.E. 02-24/25; D.T.E. 03-40; D.T.E. 05-27; see Exh. NEGC-JDS-2, at 3). Specifically, the Company contends that: (1) it estimated the marginal costs using econometric analysis; (2) it estimated the marginal costs using multi-variate regression equations, rather than simple (single explanatory variable) regression equations; (3) it employed sound statistical techniques and approaches, including testing for violations of the standard assumptions of multiple linear regressions and applying appropriate corrections when violations of the standard assumptions are observed; (4) it estimated the regression equations with 29 years of time series data; (5) its estimated regression equations do not unnecessarily rely on estimated data; and (6) it estimated only marginal distribution plant costs and marginal O&M costs (Company Brief at 133-134; see Exh. NEGC-JDS-2, at 3).

The Company states that it prepared its marginal cost study based on an analysis of the Fall River service area data only because that service area's specific marginal costs are the best estimate of the marginal costs that would apply on a going-forward basis to the integrated company (Company Brief at 133, citing Exh. NEGC-JDS-2, at 4). The Company further stated that it excluded data for the North Attleboro service area for the following reasons: (1) the two service areas (i.e., Fall River and North Attleboro) were originally operated as separate companies, and the operations were so different over the past 30 years that the combined data would not reasonably reflect the cost structure of the integrated company on a going-forward basis (Exh. NEGC-JDS-2, at 4); (2) data for the North Attleboro service area was available only for the periods 1985 to 1989 and 1993 to 2007, which left a gap of three years (i.e., 1990 to 1992), making it insufficient to reliably estimate the distribution capacity-related cost structures (id. at 5); and (3) since the formation of NEGC in 2000, the two companies have been operated on an integrated basis, and because the Fall River service area is significantly larger than the North Attleboro service area, the integrated company is substantially the same as if the Fall River service area were run on a stand-alone basis (id. at 4).

NEGC states that it will use the results of the MCS, for example, to establish floor prices for any special contracts that it may negotiate with customers in the future, and for other purposes as directed by the Department (Company Brief at 134). No other party commented on NEGC's MCS.

3. Analysis and Findings

Our review of the MCS developed by NEGC indicates that the MCS incorporates sufficient detail to allow a full understanding of the methods used to determine the marginal cost estimates. In its MCS, the Company has included the determination of six cost components: (1) the marginal cost of capacity-related distribution plant; (2) the marginal capacity-related operations expense; (3) the marginal capacity-related maintenance expense; (4) the marginal general plant expense; (5) the marginal administrative and general expense; and (6) the marginal material and supplies expense (Exh. NEGC-JDS-2, at 6).

The Department reviewed and evaluated the multiple regression method used to determine the marginal distribution capacity costs. Our review of the Company's proposed marginal distribution capacity cost estimates indicates that such estimates were calculated consistent with the Department precedent. See, e.g., D.T.E. 05-27, at 318; D.T.E. 03-40, at 375-378; D.T.E. 02-24/25, at 243-245. In particular, we note that in computing the marginal distribution capacity cost estimates, NEGC: (1) used econometric analysis; (2) used multiple variable regression equations; and (3) performed appropriate diagnostic tests to detect potential statistical problems (see Exh. NEGC-JDS-2, at 3; Schs. NEGC-JDS-2-1, NEGC-JDS-2-2; NEGC-JDS-2-3). In addition, we note that NEGC used 29 years of time series data to calculate the marginal distribution capacity cost estimates, which is just one year short of the minimum 30 years of time series data required by Department directives. See D.T.E. 02-24/25, at 243-245. In D.T.E. 02-24/25, the Department directed Fitchburg Gas and Electric Light Company to estimate its marginal distribution costs using regression equations with a minimum of 30 years of time series data. In the instant case, NEGC used 29 years of time series data due to difficulties with data availability (see Exh. NEGC-JDS-2, at 5). Because the time series data used is just one year short of the 30 years required, and due to the Company's difficulties in obtaining sufficient data, we will accept NEGC's marginal cost estimates based on the 29 years of data.

Our review of the econometric analysis used by the Company to calculate the marginal distribution capacity-related costs indicates that NEGC has sufficiently documented its method of estimation. Additionally, the Department notes that the econometric method employed by the Company is based on proven estimation techniques. The R-squared of the regression for the marginal distribution plant-related costs was 0.8289, which means that approximately

83 percent of the variation in the dependent variable can be explained by the independent variables in the regression equation. We also note that the t-statistics were greater than 2.0, indicating that the coefficient estimates of the explanatory variables used to derive the marginal cost estimates are statistically significant (see Sch. NEGC-JDS-2-1, at 1). Further, we note that the marginal distribution capacity-related cost estimates are within an acceptable level of confidence. Therefore, the Department will accept NEGC's marginal costs estimated from the econometric analysis and presented in Schedules NEGC-JDS-2-1, NEGC-JDS-2-2, and NEGC-JDS-2-3.

D. Rate Design

1. Introduction

The Company states that class revenue targets were determined based on the results of the COSS (Exh. NEGC-JDS-3, at 5). The study determined fully allocated costs at equalized rates of return for each of NEGC's rate classes (id.). According to NEGC, the fully-allocated total Company base-revenue requirement is net of the costs recovered through the CGAC and LDAC cost recovery mechanisms (id.). The Company used the class-specific, fully-allocated base distribution revenue requirement at the Company's proposed return on rate base as the initial basis for setting class revenue targets; nonetheless, based on the rate design principles of earnings stability and continuity, NEGC also considered the rate impacts on each class as a whole from increasing the revenue targets (id.).

The Company designed its base rates to recover $26,177,128 total base distribution revenue requirement (id.). The Company followed the following steps to determine class revenue targets. First, NEGC calculated current total class revenues by using pro forma normalized billing determinants and current distribution rates (id.). Second, NEGC determined the amount of the total revenue requirement to be assigned to each rate class based on the results of the COSS (id.). Third, the Company calculated class revenue increase impacts by comparing for each rate class current revenues to proposed revenues, and set a class revenue increase cap to limit the amount of the increase assigned to any class so as to satisfy the continuity rate design goal (id. at 6). Fourth, the Company assigned any revenue shortfalls that result from the class revenue increase cap to all classes whose revenue increase was below the cap to determine the final base revenue targets by class (id.).

The Company calculated total revenues at current rates by summing pro forma base revenues, plus local distribution adjustment factor ("LDAF") revenues, plus total imputed GAF revenues (id.). To calculate overall class revenue increase impacts at the proposed revenue targets, NEGC adjusted base revenues for low-income classes R-2 and R-4 to eliminate the difference between the current discounted R-2 and R-4 rates and the current regular R-1 and R-3 rates (id.). The Company calculated total fully-allocated costs by summing fully-allocated base costs, and GAF and LDAF revenues at current rates (id. at 7).

Class revenue increase impacts were determined by comparing for each rate class current revenues to proposed revenues. To do this, NEGC calculated the difference between fully-allocated base rate costs, plus proposed LDAF and GAF revenues, by class ("total potential increase") and compared them to pro forma base revenues plus pro forma LDAF revenues and imputed GAF revenues (id. at 8). NEGC then calculated the percentage change that the class-specific total potential increases represents relative to the current total class revenues (id.). To maintain rate continuity, the Company proposed that the percent increase in base rate plus LDAF and GAF revenues should be limited to 130 percent of the Company average increase (id.).

The Company stated that applying the 130 percent cap created a revenue requirements shortfall as a result of capping the increases to rate classes R-1 and R-3 (id. at 9). NEGC allocated the resulting shortfall to all classes that were below the cap by calculating the difference between the capped percent increase and the total potential percent increase for each class, weighted by the total pro forma class revenues (id.). As the final step, the Company determined the base revenue target increase for each class by subtracting the LDAF and GAF revenue increase from the total class revenue increase, which included each class' assigned share of the revenue shortfall that resulted from setting a cap for the increase to a class (id. at 9-10). NEGC added the increase to the base revenue targets for each class to the pro forma test year base revenues to determine total class revenue targets (id. at 10).

NEGC used the following steps to design base rates that would recover each rate class' revenue target. First, the Company determined the appropriate level of customer charges (id.). Second, the Company determined the appropriate ratio of peak period rates to off-peak period rates (id.). Third, the Company determined the appropriate rate differential between head block and tail block rates (id.). Fourth, NEGC calculated the final rates (id.). In addition to calculating the final rates, the Company determined the low-income discounted rates, and calculated the revenue shortfall resulting from the low-income discount (id.).

To determine the appropriate level of customer charges for each class, the Company considered (1) the fully-allocated unit customer costs calculated in the COSS, (2) a survey of Massachusetts gas distribution customer charges, (3) rate continuity, and (4) customer impacts (id. at 10-11; Sch. NEGC-JDS-3-2, at line 252). According to NEGC, the proposed customer charges for all classes except G/T-43 and G/T-53 are significantly below the allocated unit customer cost to serve because the customer rate impact showed rate continuity concerns (Exh. NEGC-JDS-3, at 11). The Company calculated class customer charge revenues by multiplying the proposed customer charges by the test year class customer counts (id.). To determine the quantity-based revenue target, NEGC subtracted the class customer charge revenues from the class revenue target (id.).

According to NEGC, the base rate seasonal ratios and the head block price differential by season were set in a manner that would promote efficiency in pricing, that would be understandable to customers, and that would not produce undue customer impacts (id. at 12; Sch. NEGC-JDS-3-2, at lines 262, 269, and 270). The Company set the low-income discount at 40 percent off the regular residential base rates (Exh. NEGC-JDS-3, at 13). The Company stated that a 40 percent discount produced reasonable and appropriate low-income base rates given the Department's recent orders concerning low-income discounted rates (id.). NEGC will recover the revenue shortfall that results from the discounted low-income rates through the RAAF (id. at 14; Sch. NEGC-JDS-3-2, at 346, 347).

NEGC proposes to consolidate the different rate structures for the Fall River and North Attleboro service areas into one set (Exh. NEGC-JDS-3, at 2). The Company states that the North Attleboro service area C&I rate class definitions are not consistent with the Department's current rate classification standards (Exh. NEGC-JDS-1, at 6). The Company also states that except for the North Attleboro service area, all Massachusetts gas LDCs classify C&I customers according to annual use and a measure of load shape (id.). Finally, NEGC notes that by maintaining separate rate classifications and separate tariffs for the Fall River and North Attleboro service areas, the Company experiences significant administrative and customer service inefficiencies (id.).

NEGC has also proposed a declining block rate structure that is seasonally differentiated (Exh. NEGC-JDS-3, at 12). Because the Company has proposed customer charges that are less than the fully-allocated customer cost of service, a portion of customer-related costs remain to be recovered through the quantity-related (i.e., per therm) charges (id. at 13). According to the Company, if the total class revenue target, net of customer charge revenues, is recovered through a single flat per-therm rate, then high use customers in that class will (1) experience significant bill increases, and (2) be charged rates that exceed the cost to provide their service, compared to appropriately designed declining block rates (id.). NEGC further stated that flat rates and rates that are not seasonally-differentiated would expose the Company to increased revenue and earnings-related risk resulting from (1) warmer than normal weather and (2) declining use per customer, compared to appropriately designed declining block rates (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company's proposed rate design is flawed and must be rejected (Attorney General Brief at 58). According to the Attorney General, the Company's proposed tariffs include significant increases to customer charges and redesign of the usage blocks as well as the reclassification of the North Attleboro service area C&I customers (id.). The Attorney General contends that these changes produce effects that will be confusing to customers and are inconsistent with the Department's rate design goals of simplicity, continuity, fairness, and revenue stability (id. citing D.P.U. 05-27, at 305).

The Attorney General asserts that because NEGC's rate design proposal produces unacceptable bill impacts, the rates for the Fall River and North Attleboro service areas should not be merged at this time (id. citing Exh. AG-FWR, at 4). The Attorney General states that although the proposed combined tariffs would result in shifting only business customers to different classes, all customers in the North Attleboro service area will see changes to their rates because those rates have been historically higher than the rates in the Fall River service area (id.).

According to the Attorney General, less than a year after full implementation of a 21 percent distribution revenue increase allowed under the terms of the Settlement in D.P.U. 07-46, NEGC seeks to increase base distribution revenues by approximately 29 percent, for a total increase of over 56 percent since August 1, 2007 (id. citing Exh. UWUA-2-7). Further, in addition to these base rate increases, the Attorney General argues that NEGC seeks to increase revenues by an additional $4.1 million through an ESM rate adjustment that could go into effect at approximately the same time as the proposed increase in this case and would have NEGC customers paying increases in excess of 74 percent of what they paid 15 months earlier, or in October 2007 (id. at 58-59).

The Attorney General claims that in addition to these increases, there are other rate changes that will increase customers' energy burdens related to increasing the low-income discount, expanding the energy efficiency budgets, and significant increases to NEGC's remediation charges (id. at 59). The Attorney General asserts that none of these increases are captured in the bill impact analyses provided by NEGC, and further asserts that under any standard, the effect of the increases is staggering (id.). Therefore, the Attorney General argues that it is important that the Department weigh the total burden to customers of these significant bill increases with the Company's desire to simplify its administrative processes (id.).

To modify the Company's rate design proposal so as to mitigate customer impacts, the Attorney General suggests that (1) NEGC should not merge the tariffs at this time, (2) customer charges should not be increased as steeply as the Company proposes, and (3) the Company should not change the size of the usage blocks as proposed (id.). In addition, the Attorney General suggests that NEGC could mitigate several C&I rate class' rates increase by capping increases based on the final revenue requirement approved by the Department in this proceeding (id. at 60).

The Attorney General also suggests additional adverse bill impact mitigation measures. First, the Attorney General recommends that customer charge increases should move the

Fall River service area charges to the current North Attleboro service area level, with no customer class experiencing increases in excess of two times the overall increase in revenues (id.). Second, the Attorney General recommends that NEGC phase-in the merging of North Attleboro service area customers into Fall River service area rates, and set certain block rates to the North Attleboro service area level, and collect the revenue difference in off-peak rates (id.).

In conclusion, the Attorney General recommends that the Department not implement the full merger of rates at this time because of the potential for customer confusion and adverse bill impacts that may be experienced by customers in an economically-stressed area (id. at 61). Further, the Attorney General argues that the Department should reject the Company's proposed rate design and instead adopt her recommendations as outlined above (id.).

b. Company

NEGC asserts that its proposed rate design is reasonable and appropriate and is supported by the evidence presented (Company Brief at 137). The Company states that the proposed rates were designed to recover $26,177,128 in base rate revenue target, which is derived from NEGC's total revenue requirement of $90,809,242, with adjustments for test year revenues that are recovered through the GAF or LDAF (id. citing Exhs. NEGC-JDS-3 at 5; NEGC-JMS-2; AG 10-1). NEGC states that, in general, the proposed base distribution rates were developed so that the level of rates charged to each class reasonably reflects the cost to serve that class, taking customer impacts into consideration (id. citing Exh. NEGC-JDS-3, at 5).

The Company argues that to maintain rate continuity, it determined that the percent increase in base rates plus LDAF and GAF revenues should be limited so as to maintain rate continuity while ensuring that the final rates to most classes would represent the cost to serve that class, and that the limited level of cost subsidization created by the cap would not unduly distort the price signals (id. at 138, citing Exh. NEGC-JDS-3, at 8). Concerning the level of customer charges, NEGC contends that it determined the proposed monthly customer charges for each class by balancing (1) the fully-allocated unit customer costs derived from NEGC's COSS, (2) a survey of customer charges billed by other Massachusetts LDCs, (3) rate continuity, and (4) customer impact analyses (id. citing Exhs. NEGC-DAH-7; NEGC-JDS-3, at 12, Sch. NEGC-JDS-3-4, Sch. NEGC-JDS-3-5; Company Reply Brief at 32). The Company argues that it determined the level of the variable rates in a manner that would promote efficiency, be understandable to customers, and that would not produce undue customer impacts (Company Brief at 138, citing Exhs. NEGC-JDS-3, at 12).

NEGC also asserts that its proposed declining block rate structure is appropriate. First, the Company asserts that its proposed seasonally-differentiated declining block rates provide more accurate price signals than other rate structures, such as flat non-seasonally differentiated rates (id. at 140, citing Tr. 2, at 254). Second, the Company contends that its base rates are approximately 27 percent of a typical residential heating customer's total bill and it is exceedingly unlikely that NEGC's proposed declining block rate structures would have any influence on any customer's incentives to use gas efficiently (id. at 141, citing Exh. DPU 3-26). Third, NEGC contends that the reduction in revenues as a result of conservation would be greater with flat non-seasonally differentiated rates than with the Company's proposed rates (id.). Given these factors, NEGC argues that its proposed rates avoid some of the financial barriers to the Company's full engagement in demand-reducing efforts that would be created by flat rate structures (id.).

NEGC argues that the Attorney General's assertion that the proposed customer charges are too high is without merit and is not supported (id. at 139). According to the Company, the Attorney General's objection to the proposed customer charges is based on her calculations of the percentage increases in the proposed Fall River service area residential R-1 and R-2 customer charges (id.). This analysis, the Company argues, is incomplete and not based on sound ratemaking principles for the following reasons (id.). First, the Company asserts that the Attorney General tried to generalize to all other rate classes the results of the analysis that relates only to the Fall River service area residential non-heating class, which represents five percent of the Company's test year customers (id.). Second, the Company asserts that the Attorney General ignores the bill impact analyses, which show that the percentage increases in customer charges that she calculated apply to less than eight percent of the peak period bills and ten percent of the off-peak bills issued (id. citing Sch. NEGC-JDS-3-5, at 1, 2, line 14). The Company states that the bill impacts for all other customers would be significantly less than the impacts that the Attorney General refers to (id. citing Sch. NEGC-JDS-3-5, at 1-2, lines 15-36). Third, NEGC asserts that the Attorney General completely ignores the unit customer cost information from the Company's COSS which shows that NEGC's proposed customer charges are significantly less than the cost basis for the customer charges (id. citing

Sch. NEGC-JDS-3-2, line 252). Lastly, the Company contends that the Attorney General's proposal is contrary to her position in other Department proceedings in which she advocated that increased customer charges were a reasonable alternative to a revenue decoupling mechanism (id. at 140, citing D.P.U. 07-50, at 33, Attorney General Comments dated Sept. 10, 2007).

NEGC states that the proposed variable rates are set higher in the peak period than in the off-peak period, because the Company's distribution system is sized to meet peak demands, and a great deal of the Company's costs are incurred based on the peak period (id.). The Company states that rates that reflect the seasonality that is associated with the way the costs are incurred provide more accurate price signals to customers to use gas wisely (id. citing Tr. at 254). NEGC states that its proposed rate structure includes seasonally-differentiated declining block rates to maintain consistency with the Company's current rates, which also include a declining block rate structure (id.). In addition, the Company asserts that a declining block structure results in more equitable intra-class rates (id.). According to NEGC, because its proposed customer charges are significantly less than the fully-allocated customer cost of service, a substantial portion of customer-related costs remains to be recovered through the variable rates (id. at 140-141). Therefore, the Company contends that eliminating the current declining block rate structure will unfairly impact high use customers because these customers would pay a disproportionate share of the customer-related costs that were not reflected in the customer charges (id. at 141, citing Exh. NEGC-JDS-3, at 13; Tr. at 1038).

NEGC claims that flat or inclining block rate structures would expose the Company to increased revenue and earnings-related risk resulting from warmer than normal weather and declining use per customer (id.). The Company argues that it would be inappropriate to adopt either a flat or inclining block rate structure without first implementing a decoupling mechanism to offset the revenue and earnings-related erosion that results from those rate structures under conditions of warmer than normal weather or declining customer use due to conservation, energy efficiency programs, or from similar causes (id. citing Exhs. NEGC-JDS-3, at 13; DPU 3-22; RR-DPU-43).

In addition, NEGC claims that a declining block rate structure does not encourage customers to use more gas compared to other rate structures such as a flat rate non-seasonally adjusted structure (id. citing Tr. at 256). In a similar manner, the Company claims that inclining block rate structures do not encourage customers to conserve, compared to other rate structures (id.). According to NEGC, because its base rates are approximately 27 percent of a typical residential heating customer's total bill, it is unlikely that the Company's proposed declining block rate structures, or inclining block structures, would have any influence on any customer's incentives to use gas efficiently (id. citing Exh. DPU 3-26).

The Company states that its proposal to consolidate the separate rate structures for the Fall River and North Attleboro service areas is reasonable, is supported by the evidence, and is consistent with Department precedent and sound ratemaking principles (id. at 135; Company Reply Brief at 28). NEGC contends that the aim of its proposal is to eliminate the inefficiencies inherent in maintaining separate tariffs for a small segment of the Company's service area and to bring the North Attleboro service area's C&I customers in conformance with the Department's rate classification standards (Company Brief at 135, citing Exhs. DPU 3-29; AG 10-4).

The Company refutes the Attorney General's argument that the rate consolidation will cause customer confusion and adversely impact customer's bills in the Fall River service area (id. citing Attorney General Brief at 59-61). According to NEGC, it has demonstrated that the current rate classifications for C&I customers in the North Attleboro service area are confusing and difficult to administer (id. citing Tr. at 273; Company Reply Brief at 28, citing Tr. at 273, 274). The Company argues that consolidation of rates will not be confusing to the affected customers (Company Brief at 135). NEGC further argues that its rate consolidation proposal is consistent with Department precedent, which requires companies to classify C&I customers on the basis of size and load factor (id.; Company Reply Brief at 28-29, citing Tr. 8, at 991). Finally, the Company argues that its rate consolidation proposal will not result in unacceptable bill impacts to customers in the Fall River service area (Company Brief at 135).

The Company also argues that the Attorney General's discussion of unacceptable bill impacts to C&I customers in the North Attleboro service area reflects a misunderstanding of NEGC's bill impact analyses (Company Reply Brief at 29, citing Attorney General Reply Brief at 37, 38). According to NEGC, the impacts cited by the Attorney General are for the off-peak period only (id. citing Exh. NEGC-JDS-3-5). NEGC states that this omission is important to the issue of whether the overall impact to these customers is acceptable because the bill impacts for G-1 customers that would be reclassified to rate classes G-51 and G-52 for the peak period are all rate decreases, except the G-1 to G-51 bill of less than 50 therms (id.). The Company further states that G-1 customers classified to rate class G-51 and rate class G-52 will experience moderate changes in their bills on an annual basis, which is the only reasonable measure of bill impacts (id. at 30).

NEGC states that the Attorney General's proposal to maintain the current rate classes in the North Attleboro service area and to hold those rates constant is without merit (Company Brief at 135-136, citing Attorney General Brief at 59). NEGC argues that the Company's proposed rates and the rates that result from the Attorney General's proposal to freeze the rates in the North Attleboro service area would have almost the same impact on customers in the Fall River service area (id. at 136). According to the Company, its proposal would increase Fall River service area customers' rates an additional 0.55 percent compared to the Attorney General's recommended rate design, and the incremental impact of NEGC's proposed rates to the largest Fall River service area rate class (residential heating, or R-3) would be an insignificant 0.15 percent (id. citing RR-DPU-42). The difference in these impacts, according to the Company, is so modest that any plan to phase-in the rate consolidation is unnecessary and unwarranted (id.).

NEGC states that the Attorney General's concern with respect to customer impacts is misplaced. NEGC asserts that its North Attleboro service area customers are currently charged significantly higher rates for the same service that Fall River service area customers are receiving (id. citing Tr. at 251). Thus, the Company argues that the Attorney General's proposal to maintain the separate North Attleboro rates causes adverse bill impacts for North

Attleboro service area customers (id.). Moreover, the Company contends that the vast majority of customer bills are already based on rates that recognize and reflect that customers in the Fall River and North Attleboro service areas receive the same service, and the Company charges the same GAF and LDAF rates to all customers (id. at 137). Therefore, NEGC asserts that there is no ratemaking justification to maintain separate base rates for these two service areas (id.).

3. Analysis and Findings

The Department must determine, on a rate class by rate class basis, the proper level to set the customer charge and delivery charges for each rate class, based on a balancing of our rate design goals, which are discussed above. The rate by rate analysis is discussed below. The Department's long-standing policy regarding the allocation of class revenue requirements is that a company's total distribution costs should be allocated on the basis of equalized rates of return. See, e.g., D.T.E. 02-24/25, at 256; D.T.E. 01-56, at 139; D.P.U. 92-250, at 194; D.P.U. 92-210, at 214. This allocation method satisfies the Department's rate structure goal of fairness. Nonetheless, the Department must balance its goals of fairness with its goal of continuity. To do this, we have reviewed the changes in total revenue requirements by rate class and bill impacts by consumption level within rate classes. Based upon our review, we accept the Company's proposal that to address the goal of continuity, no rate class shall receive an increase greater than 130 percent of the overall distribution rate increase. The Department finds that the 130 percent cap is an appropriate cap that meets our rate structure goals of fairness and continuity by ensuring that the final rates to each rate class represent or approach the cost to serve that class, that the limited level of cost subsidization created by the cap will not unduly distort rate efficiencies, and that the magnitude of change to any one class is contained within reasonable bounds (Exh. DPU 3-20). The Department directs the Company to calculate the rate increase cap as shown on Schedule 11.

The remaining revenue increase (i.e., the amount above the 130 percent cap) will be allocated first to those rate classes that would at equalized rates of return, receive a rate decrease, but only up to the amount that would eliminate such rate decrease. The allocation will be based on the ratio of each class' decrease to the total decrease for these classes. Any remaining revenue increase will be recovered on a pro rata basis based on test-year base revenues, from those classes whose revenue requirement falls below the 130 percent rate cap and who at equalized rates of return would not receive a rate decrease.[140]

NEGC has proposed to move the North Attleboro service area customers onto the Fall River service area rates (see Exh. NEGC-JDS-3, at 2). The Company states that such a consolidation is consistent with the Department's rate classification policies (id.). The Department has found that, in determining whether to consolidate or disaggregate customers into new rate classes, rate classes should be defined on the basis of differences in cost of service. D.P.U. 88-67 (Phase II) at 18. Department precedent calls for an approach for determining rate classes which minimizes cost differences within the class and maximizes cost differences among classes. Bay State Gas Company, D.P.U. 89-81, at 58 (1989); Colonial

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140 The Department does not address the issue of the changes to the size of the head blocks because we have approved a flat rate structure across all customer classes and, therefore, the size of the head blocks has no affect on the rates.

Gas Company, D.P.U. 86-27-A at 72 (1988). These differences in cost of service are primarily a function of customer load level and load pattern. Boston Gas Company, D.P.U. 84-236-A at 11 (1986). In developing new rate classes, individual customers should be grouped so that the rates they are paying are reasonably representative of the costs of serving them. D.P.U. 1720, at 136.

In the instant proceeding, the Company asserts that the current rates for C&I customers in the North Attleboro service area should be reclassified into the Fall River service area rate structure because the current rates are confusing, difficult to administer, and are not based on size and load factor. The Attorney General argues that the reclassification of the North Attleboro service area C&I customers into the Fall River rate classification produces effects that will be confusing to customers and are inconsistent with Department's rate design goals of simplicity, continuity, fairness, and revenue stability. We disagree. The Company has sufficiently demonstrated that the present North Attleboro C&I rate classification is confusing, difficult to police, creates administrative inefficiencies, and is not based on annual use and a measure of load factor or load shape (Exhs. NEGC-JDS-1, at 6; DPU 3-29).[141] We find that such a reclassification will be consistent with Department precedent, improve upon forms of fairness and efficiency, and do not violate the Department's goals of rate continuity.

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141 The load factor measure allows for the separation of the gas company's customers into two groups based on the "temperature sensitivity" of each customer's gas usage. Generally speaking, low load factor customers use gas for space heating and high load factor customers use gas predominantly for other purposes (Exh. NEGC-JDS-1, at 6 n.2).

D.P.U. 84-236-A at 11. Therefore, the Department approves NEGC's proposal to consolidate the North Attleboro service area rates into the Fall River service area rate classification.

In the instant proceeding, NEGC has proposed declining block rates that are seasonally differentiated for all rate classes (Exh. NEGC-JDS-3, at 13). NEGC argues that flat rates and rates that are not seasonally differentiated would expose the Company to increased revenue and earnings-related risk resulting from (1) warmer than normal weather, and (2) declining use per customer, compared to appropriately designed declining block rates (id.; Exh. DPU 3-22). In D.T.E. 05-27, the Department directed Bay State Gas Company ("Bay State") to set flat[142] volumetric rates that are not seasonally differentiated for rate classes R-1, R-2, R-3, R-4, G/T 40, and G/T 50 to satisfy continuity goals and produce bill impacts that are moderate and reasonable. D.T.E. 05-27, at 328-329. The Department directed Bay State to set flat volumetric rates that are seasonally differentiated for the remaining rate classes. Id. at 330, 335. The Department notes that the consumer price signal is from the total bill, and not only the distribution portion of the bill, and because the commodity portion of the bill is the majority of the total cost, consumers who reduce load will see their overall costs come down, contrary to the Company's assertion that it is exceedingly unlikely that its proposed declining block rate structures would have any influence on any customer's incentives to use gas efficiently. Although sending efficient price signals is a fundamental objective of rate design, it is always part of the balancing applied by the Department in setting rates in a manner that is

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[142] A flat rate sets the head block and tail block rates at the same level.

consistent with law and precedent. Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-A at 28 (2008).

The Department finds that the design of distribution rates should be aligned with important state, regional, and national goals to promote the most efficient use of society's resources and to lower customers' bills through increased end-use efficiency. To best meet these goals, rates should have an inclining block rate structure and any resulting loss in revenues from declining sales should be recovered through a decoupling mechanism as discussed in D.P.U. 07-50-A.

In the instant proceeding, however, the Department is concerned that moving directly from declining block rates to inclining block rates, without a decoupling mechanism, may result in a decline in sales at a level that may cause the Company not to collect its cost of service. Therefore, in consideration of this, the Department will not impose an inclining block rate structure at this time and directs for all customer classes that NEGC use a flat rate structure instead. That is, the head block and tail block should be set at the same rate that is seasonally differentiated, while maintaining the ratio of peak to off-peak revenue requirement as proposed by NEGC. In future base rate proceedings, however, NEGC and all other natural gas and electric distribution companies shall design distribution rates using an inclining block rate structure.

E. Rate by Rate Analysis

1. Rate R-1 and Rate R-3

a. Introduction

Rate R-1 is available to all residential customers for domestic non-heating purposes in private dwellings and individual apartments (Proposed M.D.P.U. No. 1003). Rate R-1 is also available for all uses by residential condominiums to the extent permitted by applicable regulations (id.). Rate R-3 is available to all residential customers for domestic heating purposes in private dwellings and individual apartments (Proposed M.D.P.U. No. 1005). Rate R-3 is also available for all uses by residential condominiums to the extent permitted by applicable regulations (id.). NEGC proposes to increase the monthly customer charge from $6.60 to $11.00 per month for Rate R-1, and from $7.80 to $12.00 per month for Rate R-3 (Proposed M.D.P.U. No. 1003; Proposed M.D.P.U. No. 1005; Sch. NEGC-JDS-3-5, at 1, 3).

The proposed R-1 delivery charge during the peak season is $0.2477 per therm for the first ten therms consumed, and $0.1977 per therm for each additional therm consumed (Proposed M.D.P.U. No. 1003). The proposed R-1 delivery charge during the off-peak period is $0.2217 per therm for the first ten therms consumed and $0.1717 per therm for each additional therm consumed (id.).

The proposed R-3 delivery charge during the peak season is $0.3817 per therm for the first 80 therms consumed, and $0.2617 per therm for each additional therm consumed (Proposed M.D.P.U. No. 1005). The proposed R-3 delivery charge during the off-peak period is \$0.3080 per therm for the first 20 therms consumed and \$0.1880 per therm for each additional therm consumed (id.).

b. Analysis and Findings

According to the Company's COSS, the embedded customer charges for Rates R-1 and R-3 are \$26.44 and \$28.20 per month, respectively (Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-4). The customer charge for R-1 customers for Massachusetts LDCs ranges from a low of \$5.04 for Colonial Gas Company's ("Colonial Gas") Lowell Division to a high of \$11.11 for The Berkshire Gas Company (id., Sch. NEGC-JDS-3-4). For the rate class R-3, the customer charge ranges from a low of \$5.04 for Colonial Gas' Lowell Division to a high of \$13.44 for Boston Gas Company ("Boston Gas") (id., Sch. NEGC-JDS-3-4).

Based on a review of the embedded costs, the bill impacts on customers, and a survey of customer charges in Massachusetts, the Department finds that an R-1 Rate, designed with a \$9.00 monthly customer charge satisfies continuity goals and produces bill impacts that are moderate and reasonable. Based on the R-3 embedded costs and bill impacts, the Department finds that a \$9.00 monthly customer charge satisfies continuity goals and produces bill impacts that are moderate and reasonable. Based on goals of simplicity and efficiency, however, the Department directs the Company to modify its volumetric charges for the R-1 and R-3 rate classes so that these rate classes are charged based on a flat rate structure (Exh. DPU 3-28, Att. A). Such rate design will also satisfy continuity goals and produce bill impacts that are moderate and reasonable. Therefore, the Department directs the Company to set the volumetric charges for Rates R-1 and R-3 to collect the remaining class revenue responsibility maintaining the ratio of peak to off-peak season revenue requirement proposed by NEGC.

2. Rate R-2 and Rate R-4

a. Introduction

Rate R-2 is a subsidized rate that is available at single locations to all residential customers for domestic non-heating purposes in private dwellings and individual apartments (Proposed M.D.P.U. No. 1004). A customer will be eligible for this rate upon verification of the customer's receipt of any means-tested public benefit program or verification of eligibility for the low-income home energy assistance program or its successor program, for which eligibility does not exceed 60 percent of the median income in Massachusetts based on a household's gross income or other criteria approved by the Department. See Investigation Commencing a Rulemaking Pursuant to 220 C.M.R. § 2.00 et seq., D.P.U. 08-104 (2008).[143]

Rate R-4 is a subsidized rate that is available at single locations to residential customers for domestic heating purposes in private dwellings and individual apartments (Proposed M.D.P.U. No. 1006). A customer will be eligible for this rate upon verification of the customer's receipt of any means-tested public benefit program or verification of eligibility for the low-income home energy assistance program or its successor program, for which eligibility

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143 Until recently, low income home energy assistance program ("LIHEAP") eligibility was set at 200 percent of the federal poverty level. On October 30, 2008, the Massachusetts Department of Housing and Community Development announced that eligibility for LIHEAP in Massachusetts is changed to 60 percent of the state median income. Accordingly, NEGC shall broaden eligibility for the low-income discount rate for natural gas customers whose incomes are within 60 percent of the state median income. See D.P.U. 08-104, at 2.

does not exceed 60 percent of the median income in Massachusetts based on a household's gross income or other criteria approved by the Department. See D.P.U. 08-104, at 2-3.

NEGC proposes that customers on Rates R-2 and R-4 receive a 40 percent discount off the total charges for Rates R-1 and R-3, respectively, using the GAF and LDAF in effect during the test year (Exh. NEGC-JDS-3, at 13-14, Sch. NEGC-JDS-3-2, at lines 308-318). The Company proposes to increase the customer charge for Rate R-2 customers from $5.04 to $6.60 and for Rate R-4 customers from $5.70 to $7.20 (id., Sch. NEGC-JDS-3-5, at 2, 4; Proposed M.D.P.U. No. 1004; Proposed M.D.P.U. No. 1006).

The proposed R-2 delivery charge during the peak season is $0.1486 per therm for the first ten therms consumed and $0.1186 per therm for each additional therm consumed (Proposed M.D.P.U. No. 1004). The proposed R-2 delivery charge during the off-peak period is $0.1330 per therm for the first ten therms consumed and $0.1030 per therm for each additional therm consumed (id.).

The proposed R-4 delivery charge during the peak season is $0.2290 per therm for the first 80 therms consumed and $0.1570 per therm for each additional therm consumed (Proposed M.D.P.U. No. 1006). The proposed R-4 delivery charge during the off-peak period is $0.1848 per therm for the first 20 therms consumed and $0.1128 per therm for each additional therm consumed (id.).

b. Analysis and Findings

Pursuant to G.L. c. 164, § 1F, the Department requires distribution companies to provide discounted rates for low-income customers comparable to the low-income discount rate in effect prior to March 1, 1998. See D.P.U. 08-4, at 36. The Department interprets G.L. c. 164, § 1F, as requiring distribution companies to provide a discount rate with a percentage discount off the total bill to achieve the 1998 discount level. See Id. The Department recognizes that companies may not achieve the 1998 discount level by solely reducing the distribution portion of the bill. In such instance, the companies should reduce the distribution rate of the bill to zero. See Id.

The Department finds that the 40 percent discount proposed by NEGC does not meet the discount level required pursuant to G.L. c. 164, § 1F, and D.P.U. 08-4. Therefore, the Department directs NEGC to design rates R-2 and R-4 in compliance with D.P.U. 08-4.

3. Rate G/T-41

a. Introduction

Rate G/T-41 is available to C&I customers not purchasing default service from the Company who have annual usage of between zero therms and 8,000 therms of gas per year and whose consumption of gas during the months of May through October is 30 percent or less of total consumption during the same calendar year as determined by NEGC (Proposed M.D.P.U. No. 1007). The Company has proposed to increase the customer charge for rate G/T-41 customers from $15.18 to $20.00 per month (id.; Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-5, at 9).

The proposed G/T-41 delivery charge during the peak season is $0.3489 per therm for the first 150 therms consumed and $0.2689 per therm for each additional therm consumed (Proposed M.D.P.U. No. 1007; Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-5, at 9). The proposed G/T-41 delivery charge during the off-peak period is $0.2409 per therm for the first 50 therms consumed and $0.1609 per therm for each additional therm consumed (Proposed M.D.P.U. No. 1007; Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-5, at 9).

b. Analysis and Findings

According to NEGC's COSS, the embedded customer charge for Rate G/T-41 is $39.79 per month (Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-4). The customer charge for rate G/T-41 customers for Massachusetts LDCs ranges from a low of $3.07 for Colonial Gas' Lowell Division to a high of $27.88 for Boston Gas (id., Sch. NEGC-JDS-3-4).

Based on a review of the embedded costs, the bill impacts on customers and a survey of customer charges in Massachusetts, the Department finds that a G/T-41 Rate, designed with a $20.00 monthly customer charge satisfies continuity goals and produces bill impacts that are moderate and reasonable. Nonetheless, based on simplicity and energy efficiency goals, the Department directs the Company to modify its volumetric charges for the G/T-41 rate class so that the rate class is charged based on a flat rate structure for the peak and off-peak seasons (Exh. DPU 3-28, Att. A). Therefore, the Department directs the Company to set the Rate G/T-41 customer charge at $20.00 per month and the volumetric charge to collect the remaining class revenue responsibility maintaining the ratio of peak to off-peak season revenue requirement proposed by the Company.

4. Rate G/T-42

a. Introduction

Rate G/T-42 is available to C&I and institutional customers not purchasing default service from NEGC who have annual usage of between 8001 therms and 100,000 therms of gas per year and whose consumption of gas during the months of May through October is 30 percent or less of total consumption during the same calendar year as determined by the Company (Proposed M.D.P.U. No. 1008). The Company has proposed to increase the customer charge for rate G/T-42 customers from $24.00 to $40.00 per month (id.; Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-5, at 10).

The proposed G/T-42 delivery charge during the peak season is $0.3043 per therm for the first 1,700 therms consumed and $0.2343 per therm for each additional therm consumed (Proposed M.D.P.U. No. 1008; Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-5, at 10). The proposed G/T-42 delivery charge during the off-peak period is $0.2167 per therm for the first 600 therms consumed and $0.1467 per therm for each additional therm consumed (Proposed M.D.P.U. No. 1008; Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-5, at 10).

b. Analysis and Findings

According to the Company's COSS, the embedded customer charge for Rates G/T-42 is $235.11 per month (Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-4). The customer charge for rate G/T-42 customers for Massachusetts LDCs ranges from a low of $2.48 for Essex Gas Company ("Essex Gas") to a high of $70.17 for Bay State (id., Sch. NEGC-JDS-3-4).

Based on a review of the embedded costs, the bill impacts on customers, and a survey of customer charges for Massachusetts LDCs, the Department finds that a G/T-42 Rate, designed with a $30.00 monthly customer charge satisfies continuity goals and produces bill impacts that are moderate and reasonable. Nonetheless, based on goals of simplicity and efficiency, the Department directs the Company to modify its volumetric charges for the G/T-42 rate class so that the rate class is charged based on a flat rate structure for the peak and off-peak seasons (Exh. DPU 3-28, Att. A). Therefore, the Department directs the Company to set the Rate G/T-42 customer charge at $30.00 per month and the volumetric charge to collect the remaining class revenue responsibility maintaining the ratio of peak to off-peak season revenue requirement proposed by the Company.

5. Rate G/T-43

a. Introduction

Rate G/T-43 is available to C&I and institutional customers not purchasing default service from NEGC who have annual usage of greater than 100,000 therms of gas per year and whose consumption of gas during the months of May through October is 30 percent or less of total consumption during the same calendar year as determined by the Company (Proposed M.D.P.U. No. 1009). NEGC has proposed to increase the customer charge for rate G/T-43 customers from $600.00 to $700.00 per month (id.; Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-5, at 11).

The proposed G/T-43 delivery charge during the peak season is $0.2185 per therm for the first 15,000 therms consumed and $0.1485 per therm for each additional therm consumed

(Proposed M.D.P.U. No. 1009; Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-5, at 11). The proposed G/T-43 delivery charge during the off-peak period is $0.1606 per therm for the first 7,500 therms consumed and $0.0906 per therm for each additional therm consumed (Proposed M.D.P.U. No. 1009; Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-5, at 11).

b. Analysis and Findings

Based on a review of the bill impacts on customers, the Department finds that the G/T-43 rate designed with an increase in the monthly customer charge from $600.00 to $700.00 satisfies continuity goals and produces bill impacts that are moderate and reasonable. Based on goals of simplicity and efficiency, however, the Department directs the Company to modify its volumetric charges for the G/T-43 rate class so that the rate class is charged based on a flat rate structure for the peak and off-peak seasons (Exh. DPU 3-28, Att. A). Therefore, the Department directs NEGC to set the Rate G/T-43 customer charge at $700.00 per month and the volumetric charge to collect the remaining class revenue responsibility maintaining the ratio of peak to off-peak season revenue requirement proposed by the Company.

6. Rate G/T-51

a. Introduction

Rate G/T-51 is available to C&I and institutional customers not purchasing default service from NEGC who have annual usage of between zero and 8,000 therms of gas per year and whose consumption of gas during the months of May through October is 30 percent or less of total consumption during the same calendar year as determined by the Company (Proposed M.D.P.U. No. 1010). NEGC has proposed to increase the customer charge for Rate G/T-51 customers from $15.18 to $20.00 per month (id.; Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-5, at 12).

The proposed G/T-51 delivery charge during the peak season is $0.3921 per therm for the first 160 therms consumed and $0.2421 per therm for each additional therm consumed (Proposed M.D.P.U. No. 1010; Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-5, at 12). The proposed G/T-51 delivery charge during the off-peak period is $0.3048 per therm for the first 120 therms consumed and $0.1548 per therm for each additional therm consumed (Proposed M.D.P.U. No. 1010; Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-5, at 12).

b. Analysis and Findings

According to NEGC's COSS, the embedded customer charge for Rate G/T-51 is $52.89 per month (Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-4). The customer charge for Rate G/T-51 customers for Massachusetts LDCs ranges from a low of $3.07 for Colonial Gas' Lowell Division to a high of $27.88 for Boston Gas (id., Sch. NEGC-JDS-3-4). Based on a review of the embedded costs, the bill impacts on customers, and a survey of customer charges for Massachusetts LDCs, the Department finds that a G/T-51 rate, designed with a $20.00 monthly customer charge satisfies continuity goals and produces bill impacts that are moderate and reasonable. Based on simplicity and energy efficiency goals, however, the Department directs the Company to modify its volumetric charges for the G/T-51 rate class so that the rate class is charged based on a flat rate structure for the peak and off-peak seasons (Exh. DPU 3-28, Att. A). Therefore, the Department directs the Company to set the Rate G/T-42 customer charge at $20.00 per month and the volumetric charge to collect the remaining class revenue responsibility maintaining the ratio of peak to off-peak season revenue requirement proposed by the Company.

7. Rate G/T-52

a. Introduction

Rate G/T-52 is available to C&I and institutional customers not purchasing default service from NEGC who have annual usage of between 8,001 therms and 100,000 therms of gas per year and whose consumption of gas during the months of May through October is 30 percent or less of total consumption during the same calendar year as determined by the Company (Proposed M.D.P.U. No. 1011). The Company has proposed to increase the customer charge for rate G/T-52 customers from $24.00 to $40.00 per month (id.; Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-5, at 13).

The proposed G/T-52 delivery charge during the peak season is $0.2997 per therm for the first 1,000 therms consumed and $0.2297 per therm for each additional therm consumed (Proposed M.D.P.U. No. 1011; Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-5, at 13). The proposed G/T-52 delivery charge during the off-peak period is $0.2224 per therm for the first 250 therms consumed and $0.1524 per therm for each additional therm consumed (Proposed M.D.P.U. No. 1011; Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-5, at 13).

b. Analysis and Findings

According to NEGC's COSS, the embedded customer charge for Rate G/T-52 is $206.25 per month (Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-4). The customer charge for rate

G/T-52 customers for Massachusetts LDCs ranges from a low of $7.53 for Colonial Gas' Lowell Division to a high of $273.27 for Essex Gas (id., Sch. NEGC-JDS-3-4).

Based on a review of the embedded costs, the bill impacts on customers and a survey of customer charges for Massachusetts LDCs, the Department finds that a G/T-52 rate, designed with a $30.00 monthly customer charge satisfies continuity goals and produces bill impacts that are moderate and reasonable. Based on simplicity and energy efficiency goals, however, the Department directs NEGC to modify its volumetric charges for the G/T-52 rate class so that the rate class is charged based on a flat rate structure for the peak and off-peak seasons (Exh. DPU 3-28, Att. A). Therefore, the Department directs NEGC to set the Rate G/T-52 customer charge at $40.00 per month and the volumetric charge to collect the remaining class revenue responsibility maintaining the ratio of peak to off-peak season revenue requirement proposed by the Company.

8. Rate G/T-53

a. Introduction

Rate G/T-53 is available to C&I and institutional customers not purchasing default service from NEGC who have annual usage of greater than 100,000 therms of gas per year and whose consumption of gas during the months of May through October is 30 percent or less of total consumption during the same calendar year as determined by NEGC (Proposed M.D.P.U. No. 1012). NEGC has proposed to increase the customer charge for Rate G/T-53 customers from $600.00 to $700.00 per month (Exh. NEGC-JDS-3, Sch. NEGC-JDS-3-5, at 33).

The proposed G/T-53 delivery charge during the peak season is $1.7638 per maximum daily contract demand ("MDCD") (id., Sch. NEGC-JDS-3-5, at 33). The proposed G/T-53 delivery charge during the off-peak period is $1.2599 per MDCD (id., Sch. NEGC-JDS-3-5, at 33).

b. Analysis and Findings

Based on a review of the bill impacts on customers, the Department finds that a G/T-53 rate, designed with an increase in the monthly customer charge from $600.00 to $700.00, satisfies continuity goals and produces bill impacts that are moderate and reasonable. Nonetheless, based on simplicity and energy efficiency goals, the Department directs NEGC to modify its volumetric charges for the G/T-53 rate class so that the rate class is charged based on a flat rate structure for the peak and off-peak seasons (Exh. DPU 3-28A). Therefore, the Department directs the Company to set the Rate G/T-53 customer charge at $700.00 per month and to collect the remaining revenue target through the MDCQ charge keeping the ratio of peak to off-peak season revenue requirement proposed by the Company.

VIII. SCHEDULES

A. Schedule 1

SCHEDULE 1				
REVENUE REQUIREMENTS AND CALCULATION OF REVENUE INCREASE				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
COST OF SERVICE				
Total O&M Expense	79,415,468	(159,085)	(626,417)	78,629,966
Depreciation and Amortization	3,588,814	2,923	0	3,591,737
Taxes Other Than Income Taxes	1,534,171	2,487	32,040	1,568,698
Income Taxes	1,726,082	(100)	(544,141)	1,181,841
Interest on Customer Deposits	15,526	0	0	15,526
Gain on the Sale of the Land	0	0	(23,620)	(23,620)
Return on Rate Base	4,529,180	(2,514)	(604,889)	3,921,776
Total Cost of Service	90,809,240	(156,289)	(1,767,027)	88,885,924
OPERATING REVENUES				
Operating Revenues	76,975,521	0	0	76,975,521
Revenue Adjustments	8,234,737	0	0	8,234,737
Total Operating Revenues	85,210,258	0	0	85,210,258
Total Revenue Deficiency*	**5,598,982**	**(156,289)**	**(1,767,027)**	**3,675,666**

* Includes deficiency relating to pension and FAS 106 expenses and deficiency relating to fixed production costs, bad debt expense on gas cost, gas cost related working capital, and gas cost bad debt working capital recoverable.

B. Schedule 2

SCHEDULE 2				
OPERATIONS AND MAINTENANCE EXPENSES				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Test Year Purchased Gas Expense	56,148,373	0	0	56,148,373
Total Adj. to Purchased Gas Expense	2,718,690	0	0	2,718,690
Total Purchased Gas Expense	58,867,063	0	0	58,867,063
Test Year O&M Expense	25,019,295	0	0	25,019,295
Depreciation	3,231,280	0	0	3,231,280
Property Tax	859,464	0	0	859,464
Payroll Tax	610,308	0	0	610,308
Interest on Customer Deposits	14,728	0	0	14,728
Other Taxes	2,591	0	0	2,591
Adjusted Test Year O&M	20,300,924	0	0	20,300,924
ADJUSTMENTS TO O&M EXPENSE:				
Payroll	282,433	0	0	282,433
Employee Benefits	(1,079,999)	62,353	0	(1,017,646)
Transportation and Work Equipment	94,279	(18,035)	0	76,244
Compressor Station Expense	(47,281)	0	0	(47,281)
Uncollectible Expense	176,605	(74,644)	(6,033)	95,928
Uncollectible Expense on Deficiency	114,869	(7,991)	(42,736)	64,142
Customer Billing and Accounting	60,846	0	0	60,846
Postage	15,040	0	0	15,040
Returned Check Fee	(2,946)	0	2,946	0
RCS Expense	(26,111)	0	0	(26,111)
Professional Fees	564,969	(3,227)	(7,780)	553,962
Management Fee	186,563	(12,975)	(162,227)	11,361
Telecommunications Expense	(38,062)	0	0	(38,062)
Insurance Premiums	226,780	(788)	(2,518)	223,474
Injuries and Damages	(297,338)	(43,519)	0	(340,857)
Rate Case Expense	181,218	(64,284)	9,646	126,580
Regulatory Assessment Fee	(17,394)	0	0	(17,394)
Rents and Leases	34,336	0	0	34,336
Reorganization Costs	(20,195)	0	0	(20,195)
Advertising and Social Club Dues	(10,467)	2,377	0	(8,090)
Other Miscellaneous Expenses	(71,893)	0	0	(71,893)
Appliance Company (non-tax and depr portion)	(180,140)	3,557	0	(176,583)
Gain on the Sale of Land	(14,172)	0	14,172	0
Divestiture of RI Operations	0	0	(351,160)	(351,160)
Inflation Allowance	115,541	(1,909)	(80,727)	32,905
Total Adjustment to O&M Expense	247,481	(159,085)	(626,417)	(538,021)
Total Adjusted O&M Expense	20,548,405	(159,085)	(626,417)	19,762,903
Adjusted O&M and Purchase Gas Expense	**79,415,468**	**(159,085)**	**(626,417)**	**78,629,966**

C. Schedule 3

SCHEDULE 3				
DEPRECIATION AND AMORTIZATION EXPENSES				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
TY Depreciation and Amortization Expense	3,231,280	0	0	3,231,280
Adjustment	375,035	0	0	375,035
Subtotal	3,606,315	0	0	3,606,315
Less Appliance	17,501	(2,923)	0	14,578
Tot. Depreciation & Amortization Expense	3,588,814	2,923	0	3,591,737

D. Schedule 4

SCHEDULE 4				
RATE BASE AND RETURN ON RATE BASE				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	98,635,841	2,463,662	0	101,099,503
LESS:				
Reserve for Depreci. and Amort.	43,612,802	105,767	0	43,718,569
Net Utility Plant in Service	55,023,039	2,357,895	0	57,380,934
ADDITIONS TO PLANT:				
Purchase Gas Working Capital	4,291,878	7,787	0	4,299,665
Cash Working Capital Allowance	1,127,833	(31,270)	(109,397)	987,166
Materials and Supplies	843,193	0	0	843,193
Total Additions to Plant	6,262,904	(23,483)	(109,397)	6,130,024
DEDUCTIONS FROM PLANT:				
Reserve for Deferred Income Tax	8,921,937	14,195	1,125,225	10,061,357
Unamortized ITC	88,610	0	0	88,610
Customer Deposits	356,102	0	0	356,102
Contributions in Aid of Constr.	0	2,349,032	0	2,349,032
Total Deductions from Plant	9,366,649	2,363,227	1,125,225	12,855,101
RATE BASE	51,919,294	(28,815)	(1,234,622)	50,655,857
COST OF CAPITAL	8.72%	8.72%	-0.98%	7.74%
RETURN ON RATE BASE	**4,529,180**	**(2,514)**	**(604,889)**	**3,921,776**

E. Schedule 5

SCHEDULE 5				
COST OF CAPITAL				
	PER COMPANY			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	-	53.00%	6.35%	3.37%
Common Equity	-	47.00%	11.40%	5.36%
Total Capital	-	100.00%		8.72%
Weighted Cost of				
Debt				3.37%
Equity				5.36%
Cost of Capital				8.72%
	PER COMPANY - ADJUSTED			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	-	53.00%	6.35%	3.37%
Common Equity	-	47.00%	11.40%	5.36%
Total Capital	-	100.00%		8.72%
Weighted Cost of				
Debt				3.37%
Equity				5.36%
Cost of Capital				8.72%
	PER ORDER			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$3,395,006,000	61.64%	6.46%	3.98%
Preferred Stock	$230,000,000	4.17%	7.76%	0.32%
Common Equity	$1,883,025,000	34.19%	10.05%	3.44%
Total Capital	$5,508,031,000	100.00%		7.74%
Weighted Cost of				
Debt				3.98%
Equity				3.76%
Cost of Capital				**7.74%**

F. Schedule 6

	SCHEDULE 6			
	CASH WORKING CAPITAL			
		COMPANY	DPU	
	PBR COMPAN	ADJUSTMENT	ADJUSTMENT	PBR ORDER
Non-Gas TY Expense	25,019,295	0	0	25,019,295
LESS:				
Depreciation	3,231,280	0	0	3,231,280
Property Tax	859,464	0	0	859,464
Payroll Tax	610,308	0	0	610,308
Interest on Customer Dep.	14,728	0	0	14,728
Other Taxes	2,591	0	0	2,591
Adjusted TY O&M	20,300,924	0	0	20,300,924
Total Adjustment to O&M Expense	247,481	(159,085)	(626,417)	(538,021)
Total Adjusted O&M Expense	20,548,405	(159,085)	(626,417)	19,762,903
LESS:				
Pension Expense	0	0	1,623,054	1,623,054
Uncollectible GAF	0	0	1,207,717	1,207,717
O&M Expense Subject to CWC	20,548,405	(159,085)	(3,457,188)	16,932,132
Total O&M CWC Allowance [1]	1,127,833	(31,270)	(109,397)	$987,166
Purchased Gas O&M	56,148,373	0	0	56,148,373
Adjustment to Purchased Gas	2,718,690	0	0	2,718,690
Purchased Gas Subject to CWC	58,867,063	0	0	58,867,063
Cash Working Capital Purchased Gas	4,211,011	0	0	4,211,011
Uncollectible GAF Subject to CWC	1,207,717	0	0	1,207,717
Total Uncollectable GAF	80,867	7,787	0	88,654
Total Purchased Gas Capital Allowance	4,291,878	7,787	0	4,299,665

[1] Per Order O&M CWC is based on a net figure of 21.28 days (21.28/365)

[2] Per Order Purchased Gas CWC is based on a net figure of 24.42 days (24.42/365)

G. Schedule 7

SCHEDULE 7				
TAXES OTHER THAN INCOME TAXES				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Test Year Payroll Tax	610,308	0	0	610,308
Adjustments	(815)	0	0	(815)
Proposed Payroll Tax	609,493	0	0	609,493
Test Year Property Tax	859,464	0	0	859,464
Adjustments	67,688	(2,327)	32,040	97,401
Total Property Tax	927,152	(2,327)	32,040	956,865
Less Appliance Program	(5,065)	4,814	0	(251)
Proposed Property Tax	922,087	2,487	32,040	956,614
Excise, Sales and Other State	2,591	0	0	2,591
Total Taxes Other Than Income	**1,534,171**	**2,487**	**32,040**	**1,568,698**

H. Schedule 8

SCHEDULE 8				
INCOME TAXES				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	51,919,294	(28,815)	(1,234,622)	50,655,857
Post-Tax Return on Rate Base	4,529,180	(2,514)	(604,889)	3,921,776
LESS:				
Interest Expense	1,747,344	(970)	270,635	2,017,066
Taxable Income Base	2,781,836	(1,544)	(875,524)	1,904,711
Taxable Income	4,507,917	(2,502)	(1,418,772)	3,086,551
Taxable Income Base				
Divided by .6171				
Massachusetts Franchise Tax	293,015	(100)	(92,288)	200,626
6.50%				
Federal Taxable Income	4,214,903	0	(1,328,977)	2,885,926
Federal Income Tax Calculated	1,433,067	0	(451,852)	981,215
34.00%				
Total Income Taxes Calculated	1,726,082	(100)	(544,141)	1,181,841

I. Schedule 9

SCHEDULE 9 REVENUES				
	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
TY OPERATING REVENUES PER BOOKS				
Base	17,621,654	0	0	17,621,654
LDAF	500,200	0	0	500,200
GAF	58,341,791	0	0	58,341,791
Other	511,876	0	0	511,876
Total	76,975,521			76,975,521
Unbilled Revenue	440,583	0	0	440,583
LDAF Related Deferral	667,733	0	0	667,733
GAF Related Deferral	(252,596)	0	0	(252,595)
Trans. Billing Related Accural	293,550	0	0	293,550
Other Variance Class Sales Report	(12,621)	0	0	(12,621)
Subtotal Adjustments	1,126,650			1,126,650
Weather and Rate Normalization Adjustment				
Base	1,724,367	0	0	1,724,367
GAF	5,012,561	0	0	5,012,561
Remove LDAC Revenue billed	(1,157,933)	0	0	(1,157,933)
Add Back Normalization LDAC PEF Revenue	1,621,060	0	0	1,621,060
Remove ECS	(82,968)	0	0	(82,968)
Remove Appliance Company Rent	(9,000)	0	0	(9,000)
Total Revenue Adjustments	8,234,737	0	0	8,234,737
Adjusted Total Operating Revenues	85,210,258	0	0	85,210,258

J. Schedule 10

SCHEDULE 10

REVENUE REQUIREMENTS AND CALCULATION OF REVENUE INCREASE BY SERVICE

	PER ORDER				AS FILED BY NEGC			
	TOTAL COMPANY	LDAF	GAF	BASE	TOTAL COMPANY	LDAF	GAF	BASE
Cost of Gas	58,867,063		58,867,063		58,867,063		58,867,063	
O&M Expense	19,762,908	1,623,054	2,916,857	15,222,992	20,548,444	1,623,054	2,802,629	16,122,761
Operations Expense	78,629,966	1,623,054	61,783,920	15,222,992	79,415,507	1,623,054	61,669,692	16,122,761
Depreciation & Amortization	3,591,737	-	147,879	3,443,858	3,588,814		147,879	3,440,935
Taxes Other Than Income Taxes	1,568,698	-	123,971	1,444,727	1,534,171		123,671	1,410,500
Income Taxes	1,181,841	-	178,797	1,003,044	1,726,084		178,797	1,547,287
Interest on Customer Deposits	15,526	-	-	15,526	15,526			15,526
Gain of the Sale of Land	(23,620)	-	-	(23,620)				
Rate Base	50,655,857	-	5,385,872	45,269,985	51,919,354		5,378,085	46,541,269
Rate of Return	7.74%	-	7.74%	7.74%	8.72%		8.72%	8.72%
Return on Rate Base	3,921,776	-	416,866	3,504,910	4,529,185		469,157	4,060,028
Cost of Service	88,885,924	1,623,054	62,651,434	24,635,056	90,809,287	1,623,054	62,589,196	26,597,037
Operating Revenues per Books	76,975,521	500,200	58,341,791	18,133,530	76,975,521	500,200	58,341,791	18,133,530
Revenue Adjustments	8,234,737	1,120,860	4,759,966	2,353,911	8,234,737	1,120,860	4,759,966	2,353,911
Total Operating Revenues	85,210,258	1,621,060	63,101,757	20,487,441	85,210,258	1,621,060	63,101,757	20,487,441
Revenue Deficiency	3,675,666	1,994	(450,323)	4,147,615	5,599,029	1,994	(512,561)	6,109,596

This schedule is for illustrative purposes only

K. <u>Schedule 11</u>

PBR ORDER BASE REVENUE INCREASE $4,147,615

Note: Schedule 11 is for illustrative purposes only.

	AS FILED BY COMPANY					
				Test Year	Proposed	Proposed
	Test Year	CGA		Non-Gas	Base Rev.	Base
	Gas	Non-Gas	LDAF	Base	Increase	Revenues
RATE CLASS	Revenues	Costs	Costs	Revenue	at BROR	at BROR
	(A)	(B)	(C)	(D)	(E)	(F)
RESIDENTIAL						
NONHEAT (R-1 & R-2)	$614,578	$32,532	$14,055	$527,189	$677,652	$1,204,841
HEAT (R-3 & R-4)	$43,882,272	$2,783,707	$1,008,164	$13,832,786	$5,538,093	$19,370,879
COMMERCIAL (LLF)						
G/T-41	$5,475,388	$361,232	$131,825	$1,807,346	$227,489	$2,034,835
G/T-42	$6,063,199	$391,190	$264,568	$2,300,892	($64,023)	$2,236,869
G/T-43	$32,499	$2,265	$46,213	$301,370	($38,190)	$263,180
COMMERCIAL (HLF)						
G/T-51	$368,552	$46,158	$20,507	$241,857	$36,501	$278,358
G/T-52	$1,930,576	$104,998	$56,544	$504,765	($44,965)	$459,800
G/T-53			$81,179	$551,328	($222,962)	$328,366
TOTAL	$58,367,064	$3,722,132	$1,623,055	$20,067,533	$6,109,595	$26,177,128

RATE CLASS	PBR ORDER Target Revenue Increase at BROR	PBR ORDER Total Bill % Increase at BROR	Revenue Increase At 130% Cap	Revenue Increase After First Revenue Reallocation	Revenue Shortfall After First Revenue Reallocation	Allocator for Shortfall After First Revenue Reallocation	Allocation of Shortfall After First Revenue Reallocation	Revenue Increase PBR ORDER	PBR ORDER Total Bill % Increase	PBR ORDER BASE REVENUES
	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
RESIDENTIAL										
NONHEAT (R-1 & R-2)	$190,900	16.06%	$76,030	$76,030	$114,871	$0	-	$76,030	6.40%	603,219
HEAT (R-3 & R-4)	$3,069,204	4.99%	$3,934,979	$3,069,204	$0	$3,069,204	114,149	$3,183,353	5.18%	17,016,139
COMMERCIAL (LLF)							-			
G/T-41	$322,408	4.15%	$497,465	$322,408	$0	$322,408	11,991	$334,399	4.30%	2,141,745
G/T-42	$354,419	3.93%	$577,056	$354,419	$0	$354,419	13,181	$367,600	4.08%	2,668,492
G/T-43	$41,699	10.91%	$24,461	$24,461	$17,238	$0	-	$24,461	6.40%	325,831
COMMERCIAL (HLF)							-			
G/T-51	$44,104	3.75%	$75,305	$44,104	$0	$44,104	1,640	$45,745	3.89%	287,602
G/T-52	$72,853	2.81%	$166,139	$72,853	$0	$72,853	2,710	$75,562	2.91%	580,327
G/T-53	$52,028	8.23%	$40,465	$40,465	$11,562	$0	-	$40,465	6.40%	591,793
TOTAL	$4,147,615	4.92%		$4,003,944	$143,671	$3,862,988	143,671	$4,147,615	4.92%	$24,215,148

IX. ORDER

Accordingly, after due notice, hearing and consideration, it is

ORDERED: That the tariffs M.D.P.U. No. 1000, M.D.P.U. No. 1001, M.D.P.U. No. 1002, M.D.P.U. No. 1003, M.D.P.U. No. 1004, M.D.P.U. No. 1005, M.D.P.U. No. 1006, M.D.P.U. No. 1007, M.D.P.U. No. 1008, M.D.P.U. No. 1009, M.D.P.U. No. 1010, M.D.P.U. No. 1011, M.D.P.U. No. 1012, M.D.P.U. No. 1013, M.D.P.U. No. 1014, M.D.P.U. No. 1015, M.D.P.U. No. 1016, M.D.P.U. No. 1017, M.D.P.U. No. 1018, M.D.P.U. No. 1019, M.D.P.U. No. 1020, M.D.P.U. No. 1021, M.D.P.U. No. 1022, M.D.P.U. No. 1023, and M.D.P.U. No. 1024 filed by New England Gas Company on July 17, 2008, to become effective August 1, 2008, are DISALLOWED; and it is

FURTHER ORDERED: That New England Gas Company shall file new schedules of rates and charges designed to increase annual gas rates by $3,675,666; and it is

FURTHER ORDERED: That New England Gas Company shall file all rates and charges required by this Order and shall design all rates in compliance with this Order; and it is

FURTHER ORDERED: That New England Gas Company shall comply with all other directives contained in this Order; and it is

FURTHER ORDERED: That the new rates shall apply to gas consumed on or after the date of this Order, but unless otherwise ordered by the Department, shall not become effective earlier than seven days after the rates are filed with supporting data demonstrating that such rates comply with this Order.

By Order of the Department,

/s/
Paul J. Hibbard, Chairman

/s/
W. Robert Keating, Commissioner

/s/
Tim Woolf, Commissioner

An appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part. Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. G.L. c. 25, § 5.